Final Report
Management Audit of
Iberdrola S.A., Iberdrola USA
New York State Electric and Gas, and
Rochester Gas and Electric

Volume I: Audit Report
Public Version
Confidential Material Redacted

Presented to:

Public Service Commission
State of New York

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June 4, 2012

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I. Executive Summary

A. Introduction

The New York State Public Service Commission (NYPSC, or PSC), in Case 10-M-0551, ordered a comprehensive management audit of Iberdrola S.A. (ISA), Iberdrola USA (IUSA), New York State Electric and Gas (NYSEG), and Rochester Gas and Electric (RG&E) in accordance with Public Service Law, Section 66(19). Such audits are required to be performed at least once every five years for combination electric and gas utilities. The law also states that "the audit shall include, but not be limited to, an investigation of the company's construction program planning in relation to the needs of its customers for reliable service and an evaluation of the efficiency of the company's operations."

Through a competitive bidding process, the PSC selected the Liberty Consulting Group (Liberty) to perform this audit. Liberty's team of fourteen experienced consultants began work in March 2011. The bulk of the research and analytical work was completed later that year. This report provides the results of Liberty's analysis, including its conclusions regarding IUSA's performance in the audit areas, and its recommendations intended for the benefit of customers.

This executive summary highlights important audit conclusions. The accompanying report sets forth the findings required to give context to those conclusions. It also provides narrative support detailing the basis for each conclusion. For each conclusion indicating an opportunity for improvement, the report provides a concise recommendation statement and supports it with underlying detail. This detail: (a) connects the recommendation to the need identified in the associated conclusion, and (b) lays out the actions proposed. An appendix to this report provides a detailed list of conclusions in each area examined. The appendix also lists each recommendation, and associates it directly with the underlying conclusion.

This audit covered a breadth of complicated management and operations areas and issues at some depth; it applied many criteria to judge performance in each area. Its focus on improvement opportunities has the inevitable result of focusing on the less positive aspects of management and operations, although it notes some areas of strength. Liberty strongly cautions readers not to rely upon this executive summary as a replacement for a reading of the entire report. Only such a reading can provide the context necessary for a full understanding of the judgments that Liberty's engagement (like all of its type) was required to make.

B. Audit Objectives

The RFP contemplated a comprehensive and thorough audit, but not one that follows the classic approach of examining utility management and operations on a functional basis, divided largely by the organizational units into which utilities then typically divided their resources. The RFP required a focus on the construction program planning, operational efficiency and performance, including reliability. This approach required an examination of the elements that comprise a cycle that flows from planning through resource assembly and structure, through key activity definition and structuring, through work planning and budgeting, through work performance and measurement, and back to planning through the incorporation of lessons learned by performance measurement. The specific cycle elements examined in this audit were:

- Corporate Mission, Objectives, Goals and Planning
- Load Forecasting
- Wholesale Market Issues
- Supply Procurement
- System Planning
- Capital and O&M Budgeting
- Program and Project Planning and Management
- Work Management
- Performance and Results Management.

This audit differed in important respects from those recently conducted under the New York Public Service Commission's renewed management and operations program. First, it involved one of the world's largest and most dispersed energy enterprises. ISA serves millions of customers dispersed largely over three continents (Europe, North America, and South America). Its size and breadth of operations have produced one of the more complex holding company structures that exist. Another significant difference is the proportionately small share of operations centered in New York. RG&E and NYSE&G are large electric and gas utilities in their own right, but they comprise fairly small percentages of ISA's total operations.

Additionally, Liberty adjusted for particular areas of emphasis the PSC's RFP accentuated, including major added areas of emphasis on:

- Governance
- Common Service Costs (arising from affiliation and a common service company)
- Consolidation of New York Operations and Rates
- Wholesale Market Issues
- Plans and Strategies for Acquisitions and Divestitures
- Compliance with Merger Order Financial Insulation Requirements
- Vegetation Management.

C. Audit Approach

1. RFP Element Organization

The table below shows the structure of Liberty's report and the location in which each RFP audit element is covered.

RFP Audit Elements / Chapter	Corporate Mission, Objectives, Goals and Planning	Load Forecasting	Wholesale Market Issues	Supply Procurement	System Planning	Capital and O&M Budgeting	Program and Project Planning and Management	Work Management	Performance and Results Management
I. Executive Summary									
II. Corporate Structure and Governance									
III. Affiliate Transactions									
IV. Load Forecasting - Electric and Gas									
V. Wholesale Market Issues									
VI. System Planning - Electric									
VII. System Planning - Gas									
VIII. Supply Procurement - Electric									
IX. Supply Procurement - Gas									
X. Budgeting									
XI. Program and Project Planning and Management - Electric									
XII. Program and Project Planning and Management - Gas									
XIII. Work Management									
XIV. Plans, Controls, Performance Management, and Compensation									

2. Audit Plan

The PSC required a detailed plan to be approved by Staff before extensive audit work began. A further requirement for this project was a definitive reconciliation among all the documents describing audit scope, including the RFP, Liberty's proposal and the audit plan. It was further required that the reconciliation address both evaluation criteria and the hundreds of activities supporting the criteria. The 300+ criteria and the hundreds of activities formed the core of the "work plan." The audit plan contains the work plan plus project definition, project requirements, budget, resource plan and schedule.

3. Audit Process

After orientation and approval of the audit plan, consultants employed a discovery process in which data requests were submitted to IUSA. Most of the nearly 1,200 data requests were processed and provided to consultants via a shared website. Consultant interviews of key IUSA and ISA personnel followed, with more than 275 conducted. Interviews included one or more consultants, the interviewee, a Company note-taker and, in many cases, one or more team members from Staff.

4. Cost Benefit Analyses

This audit also reflects a new emphasis on cost benefit analysis for recommended improvements. The Commission has been seeking to elevate the quality of the quantification of the costs and benefits associated with audit recommendations. Admittedly, the role of cost benefit analyses (CBAs) in past New York audits, including those conducted by Liberty, could be improved. Liberty therefore believed, and continues to believe, that the efforts in this regard were appropriate and Liberty committed its best efforts to meet the Commission's objectives.

Liberty developed a formal CBA process, and submitted it to the Staff for concurrence. Upon agreement between Liberty and Staff, the procedure was submitted to the Company for discussion. The Company expressed considerable concern about the proposed rate case linkage and Staff agreed that the associated language would be removed from the procedure. In addition, other changes were agreed to in order to accommodate company comments.

A total of 75 CBAs were issued, one for each of the audit recommendations contained in this report, and are included in Volume II. An attachment to this chapter provides summary table of the results of those CBAs.

5. The Straw Man Process

Liberty sought to employ a Straw Man process, in the form first attempted in the recent Con Edison audit. It would serve as a vehicle for collaboration and mutual problem-solving. The process here produced limited success. Liberty begins the process by advancing a set of hypotheses (notably, not yet "conclusions") with which the company audited may find some level of acceptance. Should common ground exist, dialog then ensues to define the issue or need more narrowly, and to work towards a mutually agreeable solution. Liberty endorses this approach in the belief that company "buy in" to a need for change produces the best, or at least the most likely to succeed, solutions.

Liberty presented four straw men to IUSA, together with an explanation of the intent of the process, and expectations for the company's hoped-for participation. Liberty dropped two of them, because the company felt it inappropriate to discuss them before the Spain meetings on governance, planned for November 2011. This timing was not consistent with project schedule.

IUSA did not respond to the third straw man, which addressed resource planning. IUSA instead asked for more support from and another presentation by Liberty. These requests did not conform to the company's prior commitments or to what Liberty viewed as needed agreement on expectations. Liberty dropped that straw man for failure to show significant potential for finding common ground.

IUSA responded favorably to the fourth straw man, which addressed cost management. Mutual efforts on that one proceeded to a favorable disposition. The cost management portions of Chapter 13 (Work Management) detail the results.

Liberty advanced at the same time a fifth potentially cooperative effort, addressing benchmarking. Liberty We did not design it formally as a straw man, but initially encouraging discussions with IUSA led to the belief that there was potential benefit in a mutually performed preliminary benchmarking analysis. If so, the expected dialogue might take much the same course and form as applicable for the four formal straw men. Liberty and IUSA reached initial agreement to work together to refine the study and seek mutually agreeable conclusions. At the meeting to kick off this effort, IUSA made clear that no common ground existed. No further efforts took place.

D. Audit Results Summary

1. Organization, Governance, and Executive Management

Liberty found that the overall organization structure ISA has created, recognizing the vast size and scope of ISA's businesses, and the size and nature of its U.S. utility operations, has the ability to support an appropriate identification and addressing of New York Utility customer needs. We did, however, find two particular concerns with how ISA and IUSA have implemented that structure. First, the lack of a consolidated gas business organization under a senior executive is not a sound means for focusing on the gas business. Second, plans recently initiated to embed an ISA affiliate as a principal source of engineering and construction management services for IUSA unduly compromises IUSA's need to re-establish a sound balance between internal and external resources. The need for attention to the restoration of that balance arises from a particularly strong focus from Spanish leadership on reducing IUSA resources over the first years of ISA's stewardship. Those reductions and the question of balancing resource types have special significance, given major expenditure commitments by IUSA, which has had difficulty in meeting them through an evenly paced construction program.

We found that IUSA has actively and appropriately been considering the costs and benefits of legal consolidation of the New York utilities. While IUSA plans continuing work in a second study phase, we believe that IUSA has appropriately concluded (as appears consistent with U.S. industry experience) that legal (versus operational) consolidation does not hold significant promise in producing economy or effectiveness. IUSA has pursued a level of functional consolidation that is consistent with industry experience, and perhaps somewhat greater in operations areas.

We found the IUSA executive team to be fully focused and engaged with respect to meeting New York customer needs. We believe, however, that it does not exhibit the hallmarks of a fully empowered and fully synchronized group. It is a "newer" team than one would normally find and it operates under an ISA structure that has created challenges. Efforts should be taken to streamline executive communications links and focus IUSA leadership under a more fully empowered CEO, emphasizing U.S. operations' needs.

We examined governance at the holding company and at the U.S. levels. ISA operates under a structured and comparatively well documented set of governance policies and guidance, procedures, and controls. The parent board also consists of distinguished and very capable individuals. ISA does not, however, strongly emphasize board member diversity of business and operating skills and experience, which contrasts the Company with what we have observed at major U.S. utility enterprises. Moreover, the structure and scope of parent board organization and activities differ significantly from what is generally accepted in the case of U.S.-based utility companies. There is not a meaningful level of independent oversight over New York utility operations at the parent level. Neither does independent oversight take place at the U.S. level. The IUSA board is the principal governing authority relevant to New York utility operations. The IUSA board has two strong independent members, but is dominated by executives of the parent.

The IUSA board committee responsible for audit matters operates under a typical and appropriate charter and list of functions, is active in defining and exercising committee activities, and has financial expertise, but is concentrated in the ISA executive management members. The committee also contains internal (*i.e.*, parent-employee) members.

A matter of recurring regulatory interest during our audit is the level of recognition in Spain of New York regulatory requirements. Senior Spanish executives and the parent board do not take a direct interest in or have more than very general knowledge of the details of U.S. regulatory requirements. We also found that management (particularly in Spain) takes an unusually restrictive and inappropriate perspective on transparency in dealing with regulatory matters.

We are not sanguine about the ability to craft constructive changes to governance needs. We did, however, make certain technical recommendations, which we emphasize do not address the issue of whether there needs to exist a source of independent oversight of U.S. operations, and, if so, how it can effectively be provided in a manner that ISA would find workable.

2. Affiliate Relationships and Transactions

NYSEG and RG&E engage in a significant amount of affiliate transactions. Support from the service company and work on behalf of each other comprise most of the dollar amount of these transactions, but the fraction involving other affiliates has been growing. The financial system and processes provide adequate capability to trace financial transactions, identify the sources of charges, and document cost assignments and allocations. Annual budgeting and service-agreement processes offer sufficient opportunity for NYSEG and RG&E to address on a sufficiently regular basis the services provided by the service company and other affiliates.

The processes for monthly review of affiliate transactions offer sufficient opportunity for NYSEG and RG&E to monitor the affiliate-provided service performance. The Company's affiliate transaction costing methods meet the requirements of the New York Code of Conduct. We also found that the inter-affiliate billing and payment process provides an adequate means for NYSEG and RG&E to review and approve the accuracy of the charges for affiliate transactions. Cost-assignment methods are adequate to provide accurate and comprehensive cost assignment of common costs to affiliates, and are consistent with the New York Code of Conduct requirements.

We also found that the service company has an appropriate cost-assignment review process. Allocation factor calculations are generally accurate and sufficiently documented. The overhead and clearing account processes are sufficient; overhead calculations are appropriate and accurate. There exist sufficient means for employees to properly assign their time to codes that allow appropriate direct charging and allocation for affiliate transactions.

IUSA requires positive time reporting, which helps to assure proper cost assignment by placing the decisions at the level at which knowledge of the specific work performed is the most accurate. There is adequate documentation and training in the use of its time reporting system and processes. The expense reporting process provides adequate means for employees to properly record and assign their expenses. The process includes sufficient controls to assure accurate and appropriate assignment of employee expenses.

The Company provides adequate documentation for its employee reporting process, and has an adequate expatriate assignment policy and process. There have been some lapses in the Company's compliance with the expatriate assignment policies and procedures, but these appear to have been corrected.

We did, however, find a significant number of processes and controls that merit improvement: (a) small (relative to best-practice in our experience) percentage of direct assignment of costs (versus use of general allocators), (b) overuse of the category of "convenience payments," which reduces transparency on transactions that involve services performed by one affiliate for another, (c) out-of-date elements in service agreements, (d) affiliate transactions not covered by service agreements, (e) lapses in timely payment for affiliate transactions, (f) no longer applicable or necessary information in the cost-allocation manual and service agreements and the limited documentation of detailed cost-allocation procedures, (g) lack of consistency in application of controls regarding accounting and cost assignment, (h) limited training and lack of a comprehensive, documented policy on training employees on proper affiliate-cost assignment, and (i) failure of time-reporting controls to minimize error occurrence. Our scope did not include the detailed examination necessary to determine whether the issues underlying these improvement areas have had a material effect on costs charged to the New York utilities.

3. Forecasting

IUSA is short on experience and capabilities in the planning and forecasting areas at the staff level. We also found that the various forecasting and planning groups and functions are weak in integration and communications, both laterally and vertically.
We found intermediate forecasts to be overly simplistic. They do not capture the broad range of economic and demographic uncertainties facing the Company. Reviews and revisions to the intermediate forecasts are informal and based on subjective, vaguely defined criteria. There is no process to revise or update the electric long-term forecast transmission model for planning purposes other than the annual updates of historical peak loads. Forecasts do not explicitly reflect public policy directives and guidelines.

4. Wholesale Markets

IUSA maintains the transmission network to meet the reliability needs for the delivery of electric supplies to all customers served by NYSEG and RG&E. The network supports access to a range of competitive suppliers to sustain New York's competitive wholesale market. The distribution network is maintained as required to support the installation and operation of distributed energy resources including distributed generation systems and such renewable resources as solar electric storage and wind generation.

IUSA strategic plans do not address the dynamics of the wholesale market and specifically identify goals and objectives that will support the needs of their retail customers in the wholesale supply and delivery of electricity. The Companies' capital and operating budgets do not demonstrate a direct linkage between each major line item and a specific strategic objective identified in the strategic plans.

IUSA has demonstrated active participation in those NYISO proceedings that can affect the short and long term interests of its retail customers. The Companies were able to demonstrate how their participation supports the development of a more robust and efficient energy infrastructure via the support of Smart Grid technologies, renewable resources and demand side management programs. Emerging regulations and transmission planning requirements will significantly increase the demand for participation and support before FERC, the NYISO and NERC at a time when the Companies have experienced diminishing resources.

IUSA should prepare a strategic assessment focused on wholesale market goals and objectives. IUSA should also create a formal matrix management team to oversee and manage the Companies' participation in NYISO, FERC, NERC, NPCC, and other proceedings, and issue assessments.

5. System Planning

a. Electricity

IUSA serves a dispersed area. The planning processes specifically reflect regional differences, as planning is performed on a divisional basis. There is, however, no long-term master plan. Planning processes do not consider risk in any measurable way, whether quantifiably or qualitatively. Senior management does not approve distribution planning guidelines, and no process exists for vetting and sanctioning design criteria changes. We also questioned the sufficiency of numbers of experienced staff.

Transmission planning guidelines do not elaborate on the economic factors, assumptions and criteria for evaluating alternative solutions to identified transmission and sub transmission requirements. IUSA applies the prioritization process uniformly; however, there is no clear understanding of how and why the parameters chosen establish the best rating system. We also found that IUSA does not use a structured approach to cost benefit analysis. Transmission planning uses the PTI PSS computer software for their evaluation of transmission upgrade requirements. IUSA does not necessarily make the best use of the available features provided in this suite of analytical tools. IUSA also does not participate in any industry wide benchmarking or best practices programs.

b. Gas

There is no formal or informal long-term gas planning process, vision or plan. The organization structure, including the recent reorganization and reassignment, is not conducive to long-term planning. There is, however, a well-developed plan for dealing with aging infrastructure; *e.g.*, replacement of leak-prone pipe (cast iron and bare steel). IUSA performs annual planning as a component of the annual budgeting process. System models are not up-to-date, which limits their accuracy and usefulness. There exists no plan to upgrade system monitoring and control capabilities. IUSA should develop a gas system vision, master plan and associated implementation strategy, including designation of the responsible individuals and organizational units.

IUSA has initiated a project team to examine business opportunities associated with Marcellus Shale and other formations. The Company has not developed scenario or contingency plans for the impacts of Marcellus Shale (and potentially Utica Shale) on its gas supply despite the enormous potential and favorable positioning of some portions of the service territory.

6. Supply Procurement

a. Electricity

IUSA does not apply to electricity supply planning a comprehensive, long-term approach with clear goals and objectives for an electricity-supply "portfolio design." It has excluded new, bilateral purchased power contracts, physical hedges and market alternatives that have durations of more than two years as potential portfolio components. The reluctance to enter into electric supply PPAs and hedges of more than two years is based on rate recovery fears. In addition, IUSA has not considered RFPs soliciting energy, hedging and capacity resources.

Planning for electric supply procurement is not sufficiently long-term to capture the load requirements and resources past two years. The examination of alternative capacity resources and markets to meet NYISO UCAP requirements has not been sufficiently aggressive. Daily electric scheduling and bidding operations are effectively conducted with appropriate risk management and approval processes.

Organization and staffing are consistent with that of effectively managed electric supply procurement groups. Procurement operations do not have a comprehensive and clearly documented process and procedures manual. Risk management operates pursuant to a well-structured program with established and enforced policies and procedures and independent oversight. However, executive committee oversight of the New York companies' risk management processes and some credit evaluations were inappropriately located in Spain; an executive risk management committee should be formed at IUSA. Internal Audit has not tested the electric procurement decisions and risk management decision-making processes.

b. Gas

The Organization and Staffing of the Gas Supply group is consistent with its mission, goal and objectives and industry practice. Key managers are well qualified and experienced. However, the experience levels of other employees vary dramatically. The Gas Supply group's very lean staffing undercuts the ability to address matters beyond day-to-day operations. Moreover, the organizational placement of Gas Supply within an otherwise all-electric unit tends to weaken the Companies' overall gas business.

Procurement policies and procedures are appropriate and consistent with work requirements. Gas Supply has developed and implemented a reasonable strategy to balance reliability and cost. Gas Supply's RFP process for winter gas appears unbiased, with reasonable analytical rigor. Local production has provided some value to date, and appears to offer very substantial value in the future if IUSA positions itself to maximize the potential benefits. The hedging program is designed to mitigate commodity price volatility, while avoiding the temptation to "beat the market."

IUSA addresses capacity and storage contracting through portfolios that represent an effective diversity of pipelines, storages, and contract expirations. IUSA has been divesting upstream pipelines as pooling points become more liquid. This approach provides benefits by reducing gas costs and increasing flexibility. Exploitation of Marcellus Shale and other indigenous sources appears to offer substantial potential for cost savings. Data from the capacity releases and off-system sales activities indicate high levels of excess capacity in the past. IUSA should review its capacity assets after evaluating its heating-degree-day calculation, in order to assure that it is current and not too high.

The Gas Control Center is understaffed in terms of both numbers and qualifications of personnel. The Gas Control Center physical facilities are significantly deficient. The organizational location of the GCC under an otherwise all-electric organization appears to drive the neglect of the GCC. The design day load forecast appears high. Short-term (one-to-five day) forecasting is relatively unsophisticated, and exhibits a high level of inaccuracy.

The NYSEG and RG&E retail-choice programs are mature, and have approached steady states. Program administration is generally fair and unbiased. Balancing strategies and practices are cost-based and unbiased toward any customer groups. Metering and testing programs conform to industry standards. The Companies' percentages of lost and unaccounted for gas are comparatively very low.

7. Budgeting

NYSEG and RG&E have been unable to execute their capital expenditure plans on a timely basis. The difficulties were significant in 2010 and 2011. IUSA does not provide adequate capital project designs, cost estimating and project planning to support the timely execution of the NYSEG and RG&E capital budgets. NYSEG and RG&E have been required to implement expedited "CAPEX catch-up additions" to capital plans in both 2010 and 2011. The cost effectiveness of such expedited efforts is dubious.

The IUSA Board of Directors has not closely examined, approved, monitored nor taken necessary corrective action regarding the capital expenditures budgets of the utilities. The NYSEG and RG&E 2010 capital budgets were not approved until September 29, 2010, almost 10 months after the budget year began and after significant capital spending. IUSA has not fully developed longer-term strategies, plans and forecasts that can be linked with three-year rate plans and the annual budget process.

O&M budget development, coordination, and consolidation are effective, in that they use consistent targets, formats, and reports. IUSA has effective management reporting processes and reports in place for executive and manager levels to track, monitor and manage O&M expenditures. Budget variances are appropriately identified and evaluated.

IUSA identifies and initiates expenditure projects and programs with appropriate and consistent system modeling. IUSA does not have a common, company-wide analysis system to evaluate and prioritize projects. There are not informational feedback loops in place to evaluate the quality of capital project analysis and prioritization efforts.

8. Program and Project Planning and Management

a. Electricity

Internal engineering resources are very low and the extensive use of contracting has not been justified. The existing team of project managers has sufficient experience in all elements of project management and has suitable credibility within the necessary work processes. The SAP Work Management system needs changes to be made fully supportive of project management needs.

The roles and responsibilities of the project manager are not clearly defined and understood throughout the organization. Expectations for project managers are consistent with the authority and resources given the project manager. Project management requirements for project participants are not generally consistent across all projects.

A holistic approach to project management is not applied. Major components of work do not have a consistently tailored “cost management plan” that describes the baseline cost, who is accountable, and how costs will be managed. Large projects contain “exit ramps” early in the job to permit management reconsideration if costs begin to escalate. Kick-off of projects requires support in the form of reasonably firm scope definition and cost-estimate quality consistent with design status.

A program of scope control is in place. It identifies scope deviations early, requires analysis of such deviations and the mandatory specification of alternates to mitigate the effects of the deviation. The construction program does not uniformly provide for the collective management of small projects. Project management principles are applied to significant O&M efforts requiring cross-functional participation. The project management program does not clearly address contractors performing project management activities. The role of quality and its relationship to cost and schedule achievement is adequately defined and understood by project participants.

There are gaps in the linkage between project management and the budgeting systems. The relative priorities of projects and programs are defined in the planning and budgeting process. A process for the handling of contingencies has not been defined. There are not clearly defined project management principles for contractor project management programs on “turn-key” projects.

A documented process is in place for the selection and award of contracts for the vegetation management program; however, there have been delays in marshaling resources and IUSA requires a more structured cycle-basis. Vegetation-management contracts for physical work include provisions that facilitate contractor work management. Performance of various contractors is compared regularly with the results used to minimize program costs on a continuing basis. An adequate number of trained utility supervisors/contract managers is assigned to the oversight of contractors. There is adequate oversight and audit of contractor management and payments.

A documented process is in place for the selection and award of contracts for the energy efficiency programs. Energy efficiency programs have a Project Manager and a documented PM process in place controlling costs, schedules and quality, but there is a gap in internal staffing. There is adequate oversight and audit of energy efficiency field operations, including contractor management, customer installations, payments and rebates. Energy efficiency program goal tracking and reporting are accurate, consistent and auditable.

RG&E and NYSEG have assigned responsibility for assessing industry and governmental (particularly DOE and NIST) developments in Smart Grid development and for assessing current network capabilities and potential improvement plans in light of those developments. The utilities have not worked actively with other state electricity distribution utilities and the Commission to address issues of deployment, standards, equipment, services, and cost recovery. RG&E and NYSEG have an analytically sound and structured process for examining the costs and benefits of network improvements. RG&E and NYSEG have taken a proactive role in examining the availability of funding support for network enhancements, and should aggressively pursue opportunities that will have demonstrable benefits for customers at effective cost.

b. Gas

IUSA does not have a workable project management function in either gas operating company. IUSA cannot demonstrate that the current system of using outside engineering resources is as labor saving or cost effective as originally proposed. IUSA needs to formalize the Gas Project Management Organization & Process by staffing a Gas project management group with experienced individuals to manage all of the capital program projects, even the small main and service replacements. The Companies should formally document project management procedures in a Project Management manual. Benefits from the increase in capital funding are jeopardized by the lack of engineering and project management resources at both IUSA and their contractors. IUSA needs to review manpower requirements to meet the capital and program requirements within the gas organization and make changes accordingly.

IUSA does not have a workable QA/QC organization and relies on operations personnel or contractor personnel to perform the QA/QC function on capital improvement and maintenance program work. IUSA needs to staff QA/QC to support an effective and functioning QA/QC program for all Gas projects and programs. IUSA has maintained an excellent compliance and safety record.

9. Work Management

IUSA's culture comports with more traditional, but not holistic, notions of cost management. IUSA's approach to cost management is similar to many other utilities, in that it is financially-oriented and focused predominantly on monitoring and oversight. The size of the current IUSA's cost support staff is small and its primary responsibility is to develop and maintain the annual budgets; cost analytical skills and cost control capabilities are lacking. The strengths of IUSA work management practices can help to form the foundation of an effective cost management system.

The existing SAP system has the ability to collect adequate and relevant cost information for current budget-management needs. Work force management reports include many charts and tables, but contain little analysis or recommendations for dealing with cost variances.

The work management processes for all physical work are pertinent, logical, and comprehensive. The current work management system module in SAP is essentially a work dispatching and work planning tool, not a complete system that is dynamic enough to manage real-time progress, productivity, and costs. The lack of planned or estimated job-hours in work packages reflects a lack of productivity emphasis and specific expectations.
The current Work Breakdown Structure provides adequate and essential details for the managers and supervisors to complete physical work. Cost estimating capability in IUSA is a major weakness; the cost estimating process is not uniformly established and approaches to estimating various types of work needs to be standardized; there are also no full-time internal professional cost estimators.

The integrity of the installation-rate databases is a concern; SAP uses the Compatible Unit (CU) to build estimated cost for every work order, but it has not been adequately maintained. The same work management processes are used in a project environment in a consistent manner. The work management system is consistent with the Company budgeting system.

Technical support during field work is responsive for emergency work and adequate for routine work. The material requisition system is effective in securing competitive pricing; the delivery of required components is well planned and expedient; the warehousing system is efficient. The Transportation Department that manages IUSA’s fleet is an effective and efficient operation; it uses a sound fleet staff analysis model in determining the right resource level to meet demand requirements. Mechanics at the garages are effective in maintaining vehicles and equipment; work crews are able to mobilize readily to work locations in a reasonably expeditious manner.

Qualifications and experiences required of supervisors are appropriate; supervisors respond actively to construction issues and resource needs in the field; supervisory ratios for both NYSEG and RG&E work are all bordering on the high end of the industry range. The training programs are generally adequate for physical workers. There is no effective resource plan to replace the aging work force. Assessments of productivity and cost impacts due to the replenishment of retired workers by apprentices are not being performed. There is a lack of long-term resource capability analysis; IUSA recognizes this need and has almost completed a work force planning model to plan for T&D Line work.

The labor agreements by NYSEG with System Council U-7 of the IBEW and by RG&E with Local 36 of the IBEW provide sufficient flexibility and essential provisions for dynamic work force management. There is a reasonable degree of flexibility in structuring crew size and allocating resources. Work crews from NYSEG and RG&E seldom cross over to work in each other’s service territories, making resource use suboptimal.

The OSHA incident rate of Gas Operations (excluding Gas Engineering) has been consistently high. The external resource requisition procedures are effective in securing competitive pricing.

Overtime levels in Gas Operations are reasonable, but T&D overtime levels at both NYSEG and RG&E are very high and a source of concern. In assigning physical work, IUSA has no articulated strategy or specific policies on balancing in-house and contractor resources.

The contractor work forces are generally efficient; there are many unit costing contractors and fixed price contractors. The substantial usage of contractors in Electric Operations underscores the question of the adequacy of internal resources. Contractor productivity is not monitored; the focus instead lies on work completion. The Contractor Performance Scorecard is not alone sufficient to ensure contractor quality and compliance.

The process of selecting supervisors is sound; the process to fill the position externally when no employees in-house are determined by management to be qualified is also acceptable. Low end work, such as flagging and underground location services, is appropriately outsourced.

With respect to performance measurement at the detailed level, productivity measurement has not been a focus of IUSA management. The new continuous improvement programs are progressing well, even though the validation of cost savings is handicapped by IUSA's inability to isolate those savings resulting from productivity improvement. There is little documentation on the implementation and effectiveness of lessons learned. The collection of production data at the work-order level adequately addresses production, but IUSA has not maximized use of data to manage productivity.

Effective productivity measurement has been lacking, but development of new KPI items initiated in early 2010 is a step in the right direction, particularly if extended to all repetitive measurable property units in both the Electric and Gas Operations. Analysis of performance metrics, in general, is inadequate, with few early warnings of potential problems or recommendations for corrective actions to mitigate factors that threaten targets. There is little effort in benchmarking internally. There is no participation in external benchmarking.

The Quality Assurance Program for Gas Operations requires significant changes and increased staffing to reach an appropriate level of effectiveness. Electric Operations needs to move in the long run away from its overly strong reliance supervisors and contracted workers to assure the quality and compliance of contractor work.

10. Plans, Controls, Performance Management, and Compensation

IUSA operates under a clear and appropriate set of mission and vision statements and clearly stated corporate objectives, which IUSA makes clear and emphasizes throughout the organization. IUSA's goals and objectives balance the needs of stakeholders, including customers, shareholders, employees and regulators. IUSA has recently adopted its first five-year plan, and recognizes, but has not yet advanced far in taking a longer-range view (ten years, initially; then extending outward after gaining confidence with a ten-year view) of its utility infrastructure.

IUSA has continued to address SOX compliance under the structure and with the methods used prior to ISA's acquisition. Reductions in key controls have occurred. The reductions do not bring

IUSA to a level that is atypical of others, but they have been substantial enough and have occurred under a sufficiently compressed period of time to warrant subjecting them to a review of their potential impact on regulatory (versus corporate) financial impact. Annual internal audit plans result from a structured risk assessment process that fully considers New York utility risks, and produces sufficient examination of utility costs. Operations audits have not been a focus of IUSA, but comprehensive processes focused on business transformation and best practice institution have produced a strong focus on operations structures, resources, procedures, and processes. Prior to two recent affiliates audits conducted after circumstances at National Grid focused attention to the issue, Internal Audit had not been conducting regular examinations of affiliate transactions.

There exist overall an appropriate set of policies, procedures, requirements, reporting, and enforcement of standards of ethical behavior and conflict-of-interest. The IUSA Code of Conduct treats affiliate relationships and transactions at too general a level. The lack of separation between legal ethics functions does not comport with our view of best practice.

IUSA regularly establishes, monitors performance against, reviews, and uses comprehensive and sufficiently quantified performance goals and targets at the high level. IUSA employs a comprehensive set of metrics and key performance indicators tied to goals and targets addressing cost and service quality. IUSA measurements adequately measure cost and service quality at the "output" level, but have yet to produce comprehensive measures of "inputs." External and internal benchmarking of performance has not strongly informed IUSA performance management.

The IUSA board examines budget performance and performance against some high-level measures and approves compensation measures, but does so at a level that we consider comparatively very general. Neither the ISA nor the IUSA boards engages at a level of sufficient detail into the establishment and management of compensation for U.S. senior management and executives.

There exist clear definitions and documentation of the program of executive compensation, but their implementation recently has lacked clarity and certainty in some respects. IUSA has designed its compensation programs to be sufficient to attract and retain personnel with the necessary levels of skill and experience, while aligning rewards with the achievement of established goals and objectives; however, it appears that IUSA has become increasingly smaller in comparison to its peer group in recent years. IUSA maintains at the general level a strong linkage between performance by and compensation of managers and executives, but the metrics used: (a) inappropriately link U.S. compensation to ISA Global performance, (b) have not "stretched" to promote performance improvement, and (c) do not sufficiently emphasize "input" as opposed to "outputs." Input measures focus on drives performance results eventually; output measures gauge results, which makes them inherently lagging indicators.

Rec. Number	**Recommendation**	**Estimated Benefits**		**Estimated Implementation Cost**	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
2.1	Suspend indefinitely the provision of services by affiliate IEP to the New York Utilities.	> $2 million per year*			
2.2	Consolidate the gas business under a single executive reporting to the COO.			$300,000	
2.3	Streamline executive communications links and focus IUSA leadership under a more fully empowered CEO, emphasizing U.S. operation's needs.		$1 million per year after two years		
2.4	Institute formal IUSA board evaluations of CEO performance and review of CEO evaluations of other top management incumbents.				
2.5	The gaps between ISA governance and what one would expect for a company with the breadth of operations of IUSA do not lend themselves to concrete, executable change recommendations.				

2.6	Make IUSA personnel a more central voice in communicating regulatory requirements, expectations, decisions, guidance and other matters to senior Spanish executives and the parent board and establish vehicles to make those audiences more aware of U.S. regulatory issues.				
2.7	Institute yearly self-assessments of board performance.				$50,000 initially, likely less than half ongoing yearly
* Note that this recommendation is connected with Chapter XI discussion of displacement of contractors.					
Rec. Number	**Recommendation**	**Estimated Benefits**		**Estimated Implementation Cost**	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
3.1	Change the identification of transactions as convenience payments to distinguish pass-through payments from expenses incurred in providing inter-affiliate services.				
3.2	Review and update the language of the inter-affiliate service agreements to reflect the current practice for affiliate transactions.				
3.3	Tighten the controls that should prevent inter-affiliate billing without a service agreement.				
3.4	Improve the timeliness of inter-affiliate bill payments.				
3.5	Improve employee training and develop more complete policy documents to encourage more direct and cost-causative charging of service company costs.				

Rec. Number	Recommendation	Estimated Benefits		Estimated Implementation Cost	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
4.1	Assign responsibility to the Rates and Regulatory Economics group for supervision and coordination of electric energy and peak load forecasting.				
4.2	Enhance the intermediate and long-term energy and load forecasting methods.			$100,000	$80,000
4.3	Enhance the economic and forecasting capabilities and competencies.			$125,000	
4.4	The company should obtain more contemporary information on customer usage patterns and time-dependent response prices and other efficiency measures.			$65,000 to $75,000 every 3 years	
4.5	Assess alternative forecasting methods.			$25,000	
4.6	Designate an oversight committee to address the management and organization issues.				
Rec. Number	**Recommendation**	**Estimated Benefits**		**Estimated Implementation Cost**	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
5.1	The Companies should prepare a strategic assessment focused on wholesale market goals and objectives.				$300,000 - $400,000

5.2	The Companies should create a formal matrix management team to oversee and manage the Companies' participation in NYISO, FERC, NERC, NPCC, etc. proceedings and issue assessments.				
Rec. Number	**Recommendation**	**Estimated Benefits**		**Estimated Implementation Cost**	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
6.1	Modify transmission planning process to include an assessment of risk and uncertainty.				$49,000 - $59,000
6.2	Prepare a comprehensive distribution planning procedures manual.			$8,000	
6.3	Perform a reevaluation of transmission planning prioritization criteria.				$4,000
6.4	Retain a power systems engineering firm to perform an independent needs assessment of its transmission planning models and methods.				$85,000
6.5	Hire an additional experienced transmission planner.			$150,000	
6.6	Participate in one or more transmission and distribution benchmarking (best practices) programs.			$80,000	

Rec. Number	Recommendation	Estimated Benefits		Estimated Implementation Cost	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
7.1	Develop a gas system vision, master plan and associated implementation strategy, including designation of the responsible individual(s) and organizational unit(s).				

Rec. Number	Recommendation	Estimated Benefits		Estimated Implementation Cost	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
8.1	Develop a comprehensive long-term portfolio management plan with quantified goals and objectives to optimize the electric resource portfolio and related hedging plans.			$75,000 - $150,000 for 5+ years	
8.2	Conduct market solicitations for electric energy resources through RFP processes and implement any alternatives identified as superior to the existing plan of energy and hedging instrument purchases.		$10 million to $23 million for one year, and 5-year savings from $44 to $113 million.	$20,000 (or less) for 5+ Years	
8.3	Conduct market solicitations for electric capacity resources through RFP processes and implement any alternatives identified as superior to the existing plan of capacity purchases.		5-year savings estimates range from $4.5 million to $27.0 million	$20,000 (or less) for 5+ Years	
8.4	Document processes, procedures, and guidelines for electric supply and scheduling.				$10,000

Rec. Number	Recommendation	Estimated Benefits: *Reduced Annual Capital Cost*	Estimated Benefits: *Reduced Annual Operating Cost*	Estimated Implementation Cost: *Increased Annual Cost*	Estimated Implementation Cost: *One-Time Cost*
8.5	An executive risk management committee should be formed at IUSA that oversees the risk functions and the RMOC and has executive responsibility for risk management.				$50,000
8.6	Internal Auditing should schedule audits of electric procurement decisions, documentation for entering into capacity supply contracts, and daily purchase decisions.			$50,000	
9.1	Upgrade the Gas Control Center personnel numbers and qualifications**.**			$146,000	
9.2	Upgrade the Gas Control Center physical facilities.				$500,000 (estimated ceiling)
9.3	Perform a weather study to determine the proper design day and design winter HDD targets.		Reduction of 1 HDD for both companies results in estimated savings of $360,584 to $516,624. Reduction of 5 HDDs for both companies results in estimated savings of $1.8 million to $2.6 million	$44,000	
9.4	Improve the short-term (one-to-five day) forecasting process.		$200,000 over 3 years	$44,000	

Rec. Number	Recommendation	Estimated Benefits		Estimated Implementation Cost	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
10.1	Complete a major overhaul of capital budgeting processes and activities, in order to produce a more structured, realistic, and supported approach to capital budget development and monitoring.				
10.2	Develop five-year and ten-year IUSA strategic plans and strongly link with rate plan forecasts and annual budgets.				$200,000
10.3	Enhance the IUSA Board's role in overseeing capital budget formation and monitoring.				
Rec. Number	**Recommendation**	**Estimated Benefits**		**Estimated Implementation Cost**	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
11.1	Determine the best balance of the number of internal project personnel for the demands for Project Managers, Project Engineers and Schedulers.	$637,500	$637,500		
11.2	Improve the project management functions of the SAP system.				
11.3	Issue written project management procedures.				$35,000 - $45,000
11.4	Separate the design function from the delivery function.				
11.5	Adopt a systematic process in place for updating SAP monthly cash flows during the budget year.				

11.6	Put vegetation management contracts in place by January 1 of the contract year.				
11.7	Move to a five year trim cycle on all circuits.		$17 million to $83 million	$18.1 million ($90.5 million over 5 years)	
11.8	Achieve the benefits of using herbicides in the distribution vegetation management program.		$0.95 million to $6.7 million*	$2.1 million	$3 million one time
11.9	Add in-house technical expertise rather than use contractors.		$134,000 per person per year		$40,000
* Note this figure is a net present value calculation that includes increased annual operating costs of $300 to $700 per mile.					
Rec. Number	**Recommendation**	**Estimated Benefits**		**Estimated Implementation Cost**	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
12.1	Formalize Gas Project Management Organization & Process by staffing a Gas project management group with experienced individuals to manage all of the capital program projects, even the small main and service replacements. Additionally, the Companies should formally document project management procedures in a Project Management manual.			$248,000 (assumes 2 PMs added)	
12.2	Review manpower requirements to meet the capital and program requirements within the gas organization and make changes accordingly.				
12.3	Staff QA/QC to support an effective and functioning QA/QC program for all Gas projects and programs.			$175,000 (plus benefits)	

Rec. Number	Recommendation	Estimated Benefits		Estimated Implementation Cost	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
13.1	Implement a holistic cost-management program.			$1.15 million	$3.86 million
13.2	Begin monitoring Actual Job-hour expenditures versus Planned Job-hours for Electric and Gas Operations; provide "Planned Job-hours" for all work packages issued to the field.	$500,000 to $750,000	$500,000 to $750,000		$20,000
13.3	Enhance the cost estimating capability by establishing a structured cost estimating program.				$150,000
13.4	Establish a structured approach, policies and supporting guidelines for the balancing of in-house and contractor resources in physical work assignments.				
13.5	Conduct a root-cause analysis on the continuous high trend in OSHA injury rate in Gas Operations and implement a corrective action program.				
13.6	Establish a structured corporate approach, policies and supporting guidelines to provide managers and supervisors with a framework to manage non-exempt employee overtime.				
13.7	Prepare an analysis of overtime expenditures on Electric Operations and Stores, including root causes of the high trends and strategies for attaining a predetermined target.				

13.8	Develop the capability to continuously assess and monitor the productivity and cost impact of the expected retirement of linemen.				$100,000
13.9	Include in future contracts a requirement that contractors performing physical work report expended job-hours and quantities installed or completed (at a property unit level).				
13.10	Evaluate the most cost-effective size of the overall internal work force, including the Mobile Work Force, taking into account such factors as future planned workload, worker versus contractor efficiency and productivity, and work rules; strive to achieve a balanced and cost-effective workforce level.		1.8 M in 1st year, $2.7 M in 2nd, $2.7 M in 3rd, $3.2 M in 4th, $3.6M/year after 4th year	$ 2.6 M in 1st year, $1.7 M 2nd, 1.7 M 3rd, $1.2 M 4th, $0.8M/yr. after 4th year	
13.11	Promote the ability of NYSEG and RG&E workforces to perform cost-effective work in each other's territories.				
13.12	Establish a Quality Assurance Organization to maintain the integrity of all the electric work performed.			$500,000 per year	

Rec. Number	**Recommendation**	**Estimated Benefits**		**Estimated Implementation Cost**	
		Reduced Annual Capital Cost	*Reduced Annual Operating Cost*	*Increased Annual Cost*	*One-Time Cost*
14.1	Study and apply the ConEd experience in long-term infrastructure planning in forming a concrete plan for long-range infrastructure planning.				
14.2	Subject prior and future changes in SOX compliance structure, structure, responsibilities, procedures, practices, and components (e.g., key controls) to a focused analysis of potential impacts on utility regulatory processes and proceedings.				$50,000
14.3	Make examination of affiliate relationships and transactions a recurring element of Internal Audit's plans and provide for clear, timely documentation and reporting of progress in implementing recommendations.				
14.4	Incorporate into the IUSA Code of Conduct specific statements of IUSA values and principles regarding affiliate relationships and transactions, and summarize and make references to applicable policies, procedures, and guidance.				
14.5	Make the reporting of the IUSA chief ethics and compliance lead organizationally separate from the general counsel's organization, establish a direct reporting organizational relationship to the IUSA CEO, and provide for regular and confidential reporting to the IUSA board's audit			$100,000	

	committee.				
14.6	Develop a series input-based metrics that will permit more robust assessment of cost performance by measuring it against work units accomplished and the productivity achieved in accomplishing those units.				
14.7	Establish a formal program applying a robust mix of external and internal benchmarks.				$250,000
14.8	Give the IUSA board the full power to design and determine the compensation of IUSA employees.				
14.9	Make the IUSA board the sole authority for establishing and measuring IUSA incentive compensation and assure the creation of all goals by the start of the period they address.				
14.10	Re-evaluate and reconstitute the peer groups used to benchmark IUSA compensation.				$50,000
14.11	Delink IUSA incentive compensation from ISA Global performance, incorporate more stretch in targets, and incorporate input measures.				
Total		**$3,137,500 to $3,387,500**	**$83,282,084to $249,021,500**	**$32,558,000.00 $104,943,000**	**$8,933,000to $9,053,000**

Corporate Structure and Governance

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II. Corporate Structure and Governance

Iberdrola SA (ISA), the ultimate parent of New York State Electric & Gas Corporation (NYSEG) and Rochester Gas & Electric Corporation (RG&E) officially advised on February 22, 2012 that it intended a significant reorganization. It would change the structure under which the New York utility businesses are owned and operated. The top level sub-parent above NYSEG and RG&E is Iberdrola USA (IUSA). IUSA is a direct subsidiary of ISA.

ISA also operates a very large wind-power business in the U.S. That business reports through a financial subsidiary; *i.e.*, Iberdrola UK Finance LTD (IUKF). The reorganization would drop IUSA from direct ISA ownership to ownership by IUKF (a directly owned ISA subsidiary). The change would also place within IUSA the U.S. portion of ISA's wind-power business. That U.S. wind-power business has been operated separately from IUSA. The following portion of this chapter discusses the IUSA organization and the U.S. wind business in more detail.

The announced reorganization came after Liberty drafted this report. Therefore, the report does not reflect the changes proposed. Those changes have the potential to moot broad and important portions of the report. Ownership, governance, organization structure, and commonality of leadership resources will clearly be affected. Planning, financial, operating, and other areas affected by this report may be affected, depending on what ISA contemplates. Liberty understands that the nature and extent of the changes will be further explored by the Commission, which will review the proposed changes in the future.

A. Background

ISA resulted from a 1991 merger of Hidroeléctrica Ibérica (founded in 1901) and Iberduero, itself formed in 1944 through a merger of companies including histories as far back as the start of the twentieth century. At about the time of its formation, ISA began real estate and engineering and construction branches, and began acquisitions and projects in Latin America. ISA embarked on a globalization strategy at the start of this century, developing and producing wind power, and acquiring utility enterprises. ISA acquired Scottish Power in 2007, and followed that by acquiring Energy East in September 2008. Scottish Power generates, transmits, and distributes electricity and provides natural gas to customers in much of Scotland and in portions of Wales. Through Neoenergia and Elektro (acquired in 2011), ISA provides generation, transmission, and distribution of electricity in much of Brazil. ISA has grown to operate in 44 countries, with 30,000 employees, who serve about 30 million customers.

ISA had in 2010, assets of €47.4 billion, operating revenues of €30.4 billion, gross margins of €11.6 billion, and about 33,000 employees. ISA has divided its operations into four groups:

- *Regulated*: Energy Transmission & Distribution in Spain, Scotland, Brazil, and the U.S.
- *Liberalized*: Electricity Generation and 3rd Party Supply in Spain, Portugal, United Kingdom, Mexico, and Continental Europe
- *Renewables*: Renewable Electricity Development and Production (predominantly wind, with hydro, solar, and biomass), primarily in Spain, U.S., and U.K., but worldwide
- *Other*
  - Engineering & Construction: Projects in 40 countries; subsidiaries/offices in 27

- Real Estate: Home, office, factory, and retail.

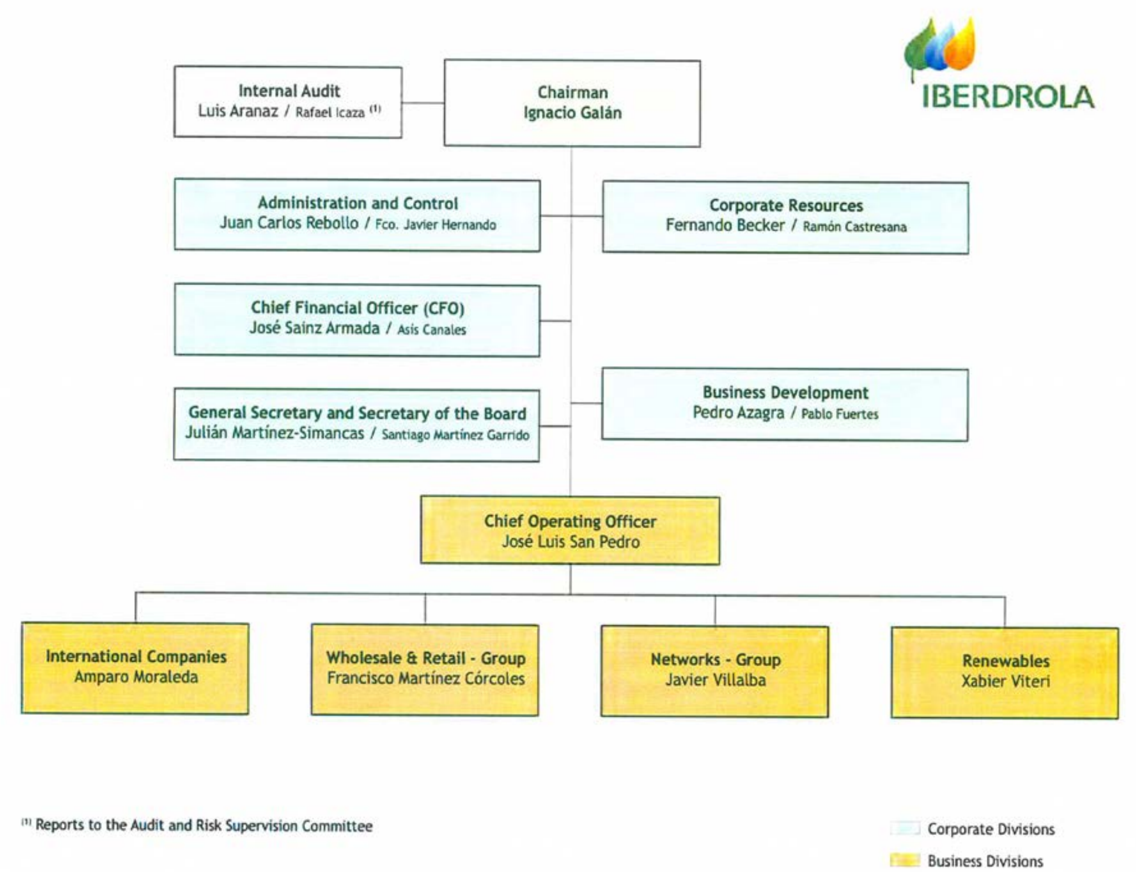
B. Corporate Structure - Findings

1. Global Business Structure

ISA describes itself as a "Group" of companies operating under the direction of a parent board of directors. This parent board defines and coordinates strategies, general guidelines, and organization structure for management of the Group. The ISA parent board seeks to provide for "strategic coordination" of all members of the Group, while promoting autonomy at the "subholding" company level. IUSA represents one of ISA's subholding companies.

The parent board establishes Group strategies guidelines for managing to those strategies, and supervises the development of strategies, guidelines, and decisions on matters strategic at the Group level. ISA's board chairman, CEO, and Senior Managers, supported by an Operating Committee (consisting of the most senior ISA executives in Spain; shown in the next table) organize and provide Group strategic coordination by disseminating, implementing, and monitoring board-established general strategy and management guidelines. The Operating Committee provides technical information, and management support with respect to general management guideline creation, supervision, and monitoring, and to strategic planning for the business managed by the subholding companies. Senior ISA managers, operating from Spain and supported by the Operating Committee:

- Implement general policies and strategies established by the parent board
- Promote the establishment of an integrated set of corporate services for the Group
- Seek to reconcile strategies among affiliates.



2. Regulated Operations

Iberdrola Distribución Eléctrica, S.A.U. (IDE) carries out ISA's principal electricity utility business in Spain. IDE serves 10.7 million points of supply in providing electricity distribution service to about 30 million people across a broad region of Spain, encompassing 25 provinces. IDE has assets of €13.9 billion, revenues of €2.0 billion, and 4,282 employees. Eight very small ISA subsidiaries serve about another 60,000 meters in Spain. Two very small gas distribution companies serve less than 1,000 customers combined.

3. IUSA's Operations

a. IUSA Utilities

NYSEG Service Territory

IUSA operates as a direct and wholly owned subsidiary of ISA. IUSA had in 2010, assets of $10.9 billion, operating revenues of $4.3 billion, and operating expenses of $3.7 billion. It had no employees. The principal utility operations of IUSA include NYSEG and RG&E; they operate under the direction of the IUSA holding company known as RGS Energy Group, Inc. (RGS). RGS had in 2010, assets of $7.6 billion, operating revenues of $2.9 billion, and operating expenses of

RG&E Service Territory

$2.5 billion. It also had no employees. NYSEG provides electricity transmission and distribution services, owns and operates some electricity generating stations, and provides natural gas transportation, storage, and distribution services upstate. NYSEG has about 880,000 electricity and 260,000 natural gas customers. It had assets of about $4.2 billion, and operating revenues of about $1.7 billion, operating expenses of about $1.5 billion, and 1,926 employees in 2010. RG&E provides electricity transmission distribution, and generation services, and provides natural gas transportation, and distribution services in western New York.

RG&E has about 370,000 electricity and 300,000 natural gas customers. It had assets of about $2.6 billion, operating revenues of about $980 million, operating expenses of about $840 million, and 832 employees in 2010. NYSEG generation facilities consist primarily of hydroelectric stations. RG&E has one coal plant, three gas-turbine plants, and some smaller hydroelectric stations.

CMP Service Territory

IUSA utility subsidiary Central Maine Power Company, Inc. (CMP) serves about 600,000 electricity distribution customers in the southern and central portions of Maine. It had assets of about $2.4 billion and revenues of about $556 million in 2010.

b. IUSA's Non-Utility Operations

IUSA operates U.S. non-utility subsidiaries. The next chart summarizes their 2010 operations.

IUSA Non-Utility Operations (dollars in millions)

Entity	Business	State	Customers	Assets	Revenues	Empl.
Energetix	Third-party E&G supply	NY	67,000 (E) 36,000 (G)	$37.6	$155.2	25
NYSEG Solutions	Third-party E&G supply	NY	131,000 (E) 26,000 (G)	$63.0	$233.8	0
Maine Electric Power	ME-NB 345kV Line	ME-NB	0	$11.0	$4.0	0
Chester SVC	Static var compensator	ME	0	$12.2	$2.9	0
Total Peaking Services	1.2Bcf LNG storage	CT	1	$11.8	$0.9	0
CNE Peaking	Peaking gas supply	CT	1	$15.6	$2.1	0
Vermont Yankee	Nuclear power plant	VT	Not Available			
Union Water Power	Real estate & consulting	ME NH	76	$6.7	$0.8	0
CT Yankee Atomic	Nuclear power plant	CT	Decommissioned			
ME Yankee Atomic	Nuclear power plant	ME	Decommissioned			
Yankee Atomic	Nuclear power plant	MA	Decommissioned			
Maine Com Services	Fiber optics & telecom	ME	55	$3.3	$2.0	0
CNE Energy Services	Gas pipeline, LNG, energy tech	CT	2	$654.1	$7.9	0
CNE Power I	*Sub of CNE Energy Services Group*		1	$8.2	$0.3	0
Aeolus Wind Power V	Wind generation	7 states	Minority Owned; Not Available			
Aeolus Wind Power VI	Wind generation	4 states	Minority Owned; Not Available			
TEN Companies	*Owns Hartford Steam & Iroquois Pipeline*		1,288	$45.6	$0.2	29
Hartford Steam	District Heating/ cooling	CT	47 + 2 elec.	$34.7	$31.3	
Cayuga Energy	Electricity Generation	NY	0	$21.6	$0	0
Carthage Energy	Elec Gen (Cayuga Subsidiary)	NY	1	$9.1	$2.4	0
PEI Power II	Cogen Facility	PA	1	$26.2	$5.1	0
So. Glens Falls	Cogen Facility(Bankrupt)	NY	0	$0	$0	0

Maine Natural Gas	Natural Gas Utility	ME	2,433	$32.1	$7.6	6
New Hampshire Gas	Propane Air	NH	1,247	$4.4	$3.1	8
Seneca Lake Storage	Gas Storage	NY	0	$0.5	$0	0
TOTALS			***265,155***	***$998***	***$459.6***	***68***

CNE Energy Services Group holds two passive Tax Equity Investments in two Renovables wind farms:

- Aeolus Wind Power V, LLC: $305.4 million invested in April 2009; source was loan from Scottish Power; 49.96 percent interest, with remainder owned by a Renovables subsidiary
- Aeolus Wind Power VI, LLC; $234 million invested in December 2010; source was proceeds from IUSA sale of the three New England gas utilities in late 2010; 16.1 percent interest, with remainder owned by a Renovables subsidiary.

c. Recent U.S. Acquisitions and Divestitures

The next table summarizes acquisitions and dispositions of U.S. companies, businesses, and operations in the past five years.

Subsidiary/Transaction	Date	Business	Assets
CNE ESG/acquired 49.96% of Aeolus Wind Power V	04/09	Wind Generation Projects	Not Avail.
CNE ESG/acquired 16.1%Aeolus Wind Power VI	12/10	Wind Generation Projects	Not Avail.
CNEESG formed CNE Power	09/09	Lease cogen system to Hartford Steam Co	$8 million
IUSA/sold 100% of Berkshire Energy Resources[1]	11/10	Natural gas distribution	$232 million
IUSA/sold 100% of Connecticut Energy Corp.[2]	11/10	Natural gas transportation and distribution	$1.45 billion
IUSA/sold 100% of CTG Resources[3]	11/10	Natural gas transportation and distribution	$1.03 billion
ENI/sold 100% of Energy East Telecommunications	10/06	Facility-based telecom infrastructure	$1.7 million

[1] Parent of Berkshire Gas Company (BGC), which serves 36,000 customers in a 520 square mile area of western Mass.
[2] Parent of Southern Connecticut Gas Company (SCG), which serves 175,000 customers in a 560 square mile area of CT.
[3] Parent of Connecticut Natural Gas Corporation (CNG), which serves 155,000 customers in 5,757 square miles of CT.

CNE ESG is CNE Energy Services Group, Inc. ENI is The Energy Network, Inc.

ISA also made a number of U.S. acquisitions and divestitures in the past five years:

- Between July 2008 and February 2009, acquired seven wind-generation project companies in various regions, and totaling 385MW
- Between December 2010 and February 2011, acquired three wind-generation project companies, totaling 711MW.

Renovables and other ISA subsidiaries (e.g., Aeolus and Scottish Power entities) made some 130 acquisitions or incorporations and 30 divestitures (largely wind and natural gas) in the last five years.

IUSA entered into transition-service agreements in connection with its sale of the three New England gas utilities in late 2010 to UIL, the parent of United Illuminating Company, a major Connecticut utility. The services covered include Information Technology, Human Resources, Purchasing and Materials Management, Finance and Accounting. All services, except for Purchasing and Materials Management, continue to be provided. IUSA has stated that it intends to complete by the end of June 2011 an evaluation of actions needed upon termination of the provision of remaining services to UIL The agreement provides for the provision of services as provided to the gas companies during their ownership by IUSA, unless otherwise agreed. Actual cost, as calculated pursuant to the IUSA costs allocation manual, to determine the price for services. The agreement has a base term of 12 months. It allows for up to four 90-day extensions and for early, no-cause termination by UIL on 90-day notice. UIL has no liability for IUSA costs following termination. The agreement contains "Critical Performance Measures," which establish metrics for assessing the sufficiency of performance.

4. Liberalized Operations

Iberdrola Generación, S.A. (IGen) designs, constructs, and operates generating units in Spain, on both provider-of-last-resort and third-party-supply bases. IGen also has operations in Portugal (hydro plant development and retail activities), the U.K. (nuclear plant development), and wholesale activities in France, Italy, Germany, Poland, the Czech Republic, and Rumania (through separate subsidiaries). IGen also supplies natural gas to about 700,000 retail customers, virtually all of them on a third-party-supply basis. IGen had in 2010 €10.8 billion in assets, €7.6 billion in revenues and 2,233 employees.

5. Renovables (Renewables)

ISA had owned 80 percent of Iberdrola Renovables, S.A. (Renovables), with 20 percent in public hands. Recently, ISA acquired the remaining 20 percent, merging Renovables into ISA. Renovables operates world-wide, directly and through many affiliates, to produce electricity from renewable resources. It ranks as the world's top wind-energy producer. The U.S., Brazil, Mexico, Spain, the U.K., Greece, Portugal, Italy, Canada, Poland, Germany, France, Rumania, Estonia, Latvia, Bulgaria, Australia, Turkey, and Hungary are all home to Renovables generators. Subsidiaries of Renovables also operate a substantial natural gas business, in addition to serving as a leading wind generator. Renovables owns 636MW of U.S. gas fired generation, conducts energy and natural gas trading and operates a gas storage business. Renovables had in 2010 €25.8 billion in assets, €2.2 billion in revenues, and 2,064 employees.

6. IUSA's Engineering and Construction Affiliate

a. II&C's Business

Iberdrola Ingeniería y Construcción (II&C, or Iberdrola Engineering and Construction) operates as an ISA subsidiary. II&C leveraged its role as the principal engineering and construction arm for ISA's Spanish utility operations to become Spain's largest engineering company. It now provides engineering, construction, and construction management services in the amount of €1.5 billion per year, through a staff of 2,400. Work for affiliates has continued to diminish substantially as a portion of total operations. Despite a large growth in operations elsewhere, II&C's U.S. operations have remained small. Iberdrola Energy Products (IEP) operates as one of II&C's U.S. subsidiaries. ISA seeks to place IEP in a utility-support role similar to that of other II&C operations in Europe.

b. Scale of II&C's U.S. Business

Outside the U.S., II&C constructed 3,000 MVA in substations in 2008 and 280 miles of 220 through 400kV transmission lines. II&C emphasizes its leadership and wide experience in undergrounding substations and extra high voltage transmission, neither of which have particular applicability in the IUSA serving region. The current strategic plan cites new markets in the U.S.

and the U.K. and new products in the areas of thermo-solar, nuclear, and off-shore wind power. The list of projects presented includes:

- One wind farm in the U.S.
- One wind farm in Mexico
- One combined cycle generating station in Mexico
- One transmission grid project in Mexico.

IUSA presented a number of other U.S. projects of II&C:

[redacted]

- A completed $2 million operations center for affiliate Renovables
- Award of a $20 million Massachusetts wind farm (Hoosac Wind) contract with Renovables (project approvals remain delayed)

[redacted]

- Competed under a number of New York and Maine RFPs, [redacted]

Engineering and project management of electric substation and transmission projects have been cited. The affiliate's 2010 staffing was 10, with a target of [redacted] in 2011. It has experienced [redacted] sales in the U.S. since 2008, [redacted]. U.S. services account for about [redacted] per year.

c. Plans to Embed II&C into IUSA's Organization

II&C's U.S. operations raise issues of particular importance to IUSA. ISA plans to make II&C (through its subsidiary IEP) a major supplier of engineering and construction management services to the New York utilities. The Commission has recently had occasion to address the use of IEP in this fashion. Liberty's request for a description of the requirements imposed by the Commission on decisions to use IEP, measurements of its performance, techniques for comparing its costs, and methods for determining the costs that NYEEG/RG&E would pay for goods and services from IEP produced a reference to the September 28, 2008 merger order and the agreed-to Code of Conduct that generally addresses affiliate transactions.

Liberty also asked for internal IUSA and affiliate documents controlling these decisions, techniques, and methods. IUSA identified only requirements that, pursuant to the provisions of its Code of Conduct, the utilities make an annual filing of affiliate transactions with the Commission. Liberty also asked for all documented procedures, policies, guidelines, forms, and other documents intended to be used to assure and demonstrate compliance with Commission requirements and internal controls. IUSA again referred to the annual filing, and stated that it will arrange for "an audit of the IEP charges." IUSA stated that the audit of IEP charges would be conducted as part of these annual filings, but provided no description of audit scope or whether and what standards or criteria the audit would apply to the specific dimensions of service about which Liberty inquired.

The Code of Conduct (Section 5) permits the provision of "corporate shared services" to be provided by an affiliate to NYSEG or RG&E on a "fully-loaded cost basis." The Code defines such service broadly, *e.g.*, to include engineering and construction, as opposed to the administrative, "back-office" functions (*e.g.*, governance, legal, accounting, IT) typically provided by the service companies of utility holding companies. Services other than shared services must be provided at the lower of actual cost or market value. On September 24, 2010, ISA and various affiliates filed a petition seeking to amend the Code of Conduct to permit an exception to the use of fully-allocated costs required for shared services (then being provided by IUMC, a single-entity successor to the two service companies existing at the time of ISA's acquisition of Energy East).

The petition cited II&C's engineering and construction experience. The petition did not limit the exception to the Code fully-allocated costing standard either to II&C or to engineering and construction services. The petition cited II&C as a 2,400-employee enterprise. It has six employees in the United States. The petition also cited a range of annual work estimated to be between 5 and 20 million dollars. The petition did not limit the work that could be performed to any amount.

- The relief requested in the petition was to change the Code's pricing provision to permit "unregulated affiliates" to "participate in the Management Corp.'s [IUMC's] competitive procurement process" on a "nonpreferential and non-discriminatory basis as set forth in the Procurement Procedures Affiliate Standards of Conduct."

IUSA and the affiliate have not described the size or dollar value of projects for which it might be considered. IUSA's petition was intended to permit any affiliated provider (not just II&C) to compete for work for the New York utilities. The petition would also permit sole source awards to an affiliate in accord with company procurement procedures. IUSA proposed no changes to those procedures, and it appears that such changes lie within the discretion of the company. IUSA listed 14 other firms as the minimum expected competitors for electrical engineering projects overall (with the number participating on any given RFP subject to conditions prevailing at the time).

An April 21, 2011 order of the Commission denied the Code change. That order cited a number of concerns:

- Speculative benefits, compared with the risk that costs to the utilities could increase
- Lack of demonstration that existing, third-party contract sources are inadequate to meet utility needs efficiently and economically
- Lack of demonstration that affiliate participation will lower prices submitted by other bidders
- Chilling effect that fears of preferential treatment of affiliates might produce
- Lack of limits on participation by other affiliates for other services
- Loss of the utility protection offered by requiring affiliate pricing to be at the lower of market price or fully-loaded costs
- Risk of higher costs through overweighting non-price bid factors in a manner that could favor affiliates
- Lack of a true limiter on value of work awardable to affiliates

- Loss of expected volume discounts to the utilities through inclusion of goods and materials under service contracts with an affiliate.

This order denied the Code change and therefore the power to price in accord with competitive solicitation results. It did not, however, preclude the provision of services from II&C or any other affiliate. The order observed that the existing Code permits affiliate-provided services at fully-loaded cost, when less than market price.

NYSEG and RG&E have signed, effective September 1, 2011 a service agreement with IEP, an II&C subsidiary. The agreement establishes the following pricing basis for services provided by IEP:

> *It is the intent of this Service Agreement that charges for services shall be the fully-loaded costs and shall not include any profit margin. The method of assignment of cost shall be subject to review by the Service Company annually, or more frequently if appropriate; provided that, in each instance, all services rendered hereunder shall be at actual cost thereof. The Service Company shall review with the Client Company any proposed material change in the method of assignment of costs hereunder and the parties must agree to any such changes before they are implemented.*

The agreement explicitly allows, "compensation for use of capital as permitted by applicable laws and regulations." The agreement requires IEP to maintain its accounts and records in accord with FERC service-company accounting requirements, and to provide the utilities with access to account information and the basis for computing fully-loaded costs.

The list of services to be provided discusses a very broad range of service types generally associated with both capital and O&M programs. It is not limited to narrowly defined engineering and construction management services. For example, the services extend to utility regulatory approval and compliance, real estate acquisition, community and government relations, coordinating legal requirements with local officials, media services, cost management (i.e., what would encompass owner monitoring of contractor costs, notable because IEP will be one of the contractors), program risk management, and performance measuring and monitoring.

Moreover, even this broad list of services is not exhaustive. The list follows an overall scope statement, which the list does not restrict, which states as follows, "Assist in the management and delivery of New York State Electric & Gas Corporation processes." That statement does not state that the processes involved are only those that follow in the succeeding list of services. Finally, even this particularly broad first statement of scope is qualified to state that it "includes, but is not limited, to" the broad scope statement and each item on the list that follows. This description places an essentially unconstrained scope of services under the agreement.

d. Recent IUSA Staffing Trends and the Use of IEP

Several of the later chapters of this report address concerns about staffing reductions at IUSA. Embedding II&C subsidiary IEP into the IUSA organization at this complicates the process of optimizing IUSA's resource mix (again, as discussed in following chapters). IUSA has not conducted analyses of replacement needs or costs associated with retirements in the physical work force, but states that it is in the "preliminary stages" of developing the capability to do so. The next table shows that retirements have been significant recently, while replacements have been nominal. Retirements at RG&E likely would have been much more substantial, but the union there has only recently accepted a voluntary early retirement program, as NYSEG bargaining unit workers did some time ago. The table also shows a clear change in approach after 2008, from an essentially one-to-one replacement to virtually no replacement.

IUSA Worker Retirements/Replacements

Year	**2008**		**2009**		**2010**	
Changes	*Retirements*	*New Hires*	*Retirements*	*New Hires*	*Retirements*	*New Hires*
NYSEG	40	42	54	2	155	2
RG&E	6	0	6	0	4	0
Totals	46	42	60	2	159	2

Force reductions formed a central element of [redacted] early focus on U.S. operations. Senior executives [redacted] used Spanish and Scottish force numbers as a benchmark in determining that U.S. operations required significant reductions. Senior Spanish executives and parent board members stress their lack of detailed knowledge about the details of U.S. operations. Surprisingly, given that approach, [redacted] Interviewees in Spain do not recall this focus, and top management viewed interest in employee numbers in the U.S. as a function not of concern about overstaffing, but of awareness that defined benefit plans in the U.S. (as opposed to the more generally applicable defined-contribution approach in the remainder of ISA's global footprint) made funding a matter of continuing interest.

[redacted] In any event, Spanish executives most directly responsible for U.S. operations acknowledge that reducing costs through reducing employees was a critical early focus under ISA's ownership and that benchmarking U.S. employee numbers was a source of the belief that reductions could be made effectively. Moreover, senior IUSA executive management has acknowledged that benchmarking U.S. employee numbers to Spanish and Scottish counterparts has driven U.S. employee reductions and that Spanish leadership has recently begun to recognize that differences in U.S. conditions (*e.g.*, vegetation and weather) bring into question reliance on European benchmarks.

7. Rate and Operations Consolidation

a. 2011 Consolidation Study Plans

IUSA decided in the fall 2010 to study consolidation of the NYSEG and RG&E electric and gas businesses during 2011. There have been no prior studies of consolidation. The New York President and the IUSA General Counsel formed the team to conduct the study. The New York president anticipated that much of the synergies and savings that might come from consolidation have probably been captured already by consolidation of many services provided to the four New York Utility operations. Bargaining unit issues were expected to comprise another major factor in considering consolidation. One agreement with the Council of Seven Unions expires in 2013; RGE's union contract expires in 2015.

A charter and schedule has guided the study, which has produced the planned first phase report. The study team has operated under the direction of the IUSA General Counsel, the New York President, and the Vice President–Regulatory Strategy. The charter guiding the study anticipated addressing legal, regulatory, financial, accounting, tax, bargaining unit, benefits, electric and gas supply, and timing. The phase-one scope excluded the effects of consolidation operations (listing Electric Operations, Operations, Customer Service, IT, Engineering and Asset Management, and General Services, and citing them as unripe for consideration until the completion of the issues slated for phase-one consideration.

b. Phase One Consolidation Study Report

The Company generated in July of this year the expected phase-one report, titled NYSEG/RG&E Consolidation Study Report. It examined legal, regulatory, finance, control, human resources and energy supply issues affecting a legal consolidation of the two companies. The report concluded that a legal consolidation would cost about $6 million in one-time costs and $5 million per year on a recurring basis, while generating only about $1 million in annual savings. The report also noted the existence of "significant rate and service class differentials." The report concluded also, however, that IUSA subsequently investigate: (a) the potential for additional operations consolidation, and (b) "alignment of tariff terms and conditions and service classes." These activities form the basis for phase two work.

The bulk of the costs postulated would arise from a one-time effort to consolidate rates (about $2.1 million for electricity and $1.2 million for gas). A consolidation would require a number of state and federal regulatory filings, and involve local franchise issues. Much of the remaining one-time costs arise from the legal fees needed to make and manage required filings. Other legal costs would arise from the need to transfer property and environmental permits, and to change various debt agreements and instruments (*e.g.*, intellectual property, leases, easements, and air, water, and waste permits).

The research, filings, and proceedings involved in a legal consolidation could take up to two years.

The report observed that the current rate plan (citing Appendix S, provision K.1 of the Joint Proposal) contemplates an examination of ways to bring more consistency to the two companies' electric and gas rate structures and service classifications. The report divided non-rate tariff differences into three categories:

- Similar language and intent; require only a straightforward language change
- Similar item, but differing language or intent; analyze before change recommended
- Item appears in only one of the Company's tariffs; analyze before change recommended.

The plans for addressing tariff conformity on non-rate issues are: redline the tariffs to address the first category, meet with Staff to discuss the changes, and make filings to cause the changes. The filings seeking changes to the first category will be made in the near term; those in the second two categories would occur in the next rate filing.

The report identified and proposed means for rationalizing service classifications (for rate purposes) between the two companies, in order to calculate the results of establishing one set of rates applicable to each company. It also showed the differences resulting from placing both sets of electric and gas customers under one, consolidated set of rates. The net rate impacts would be substantial, with significant differences among the various rate classes. Electric rates would become significantly higher for NYSEG customers, but lower for RG&E customers. The effect would be reversed for gas rates.

Significant operations differences underlie the costs differences between the two New York utilities. RG&E serves an area of 2,700 square miles, which contains a population of 1 million. By contrast, NYSEG (20,000 square miles and a population of 2.5 million) serves an area that is about 7.5 times greater, but has a population that is only 2.5 times greater. RG&E employs only 55 percent of the distribution circuit miles (per customer) that NYSEG does to serve electricity customers. The gas infrastructure ratio (measured by miles of distribution pipe) falls much closer; RG&E employs 94 percent of what NYSEG does.

c. Rate Consolidation Efforts

Significant rate consolidation actually began in 2002, by reducing the number of different NYSEG gas rate areas, and reached completion in 2010. The most recent rate case placed both NY utilities and both electric and gas operations in the same case and of the same "vintage." This commonality advances the ability to consolidate rates. Issues that need to be overcome to support rate consolidation include:

- Aligning different classes of service between the utilities and their two utility businesses
- NYSEG's lower electric delivery but higher gas rates
- Differing electric energy rates
- Differing tariff terms and conditions
- Differences in accounting records.

The two electric companies have largely worked through the separate and unique amortizations associated with restructuring. This progress improves prospects for rate consolidation, as does the alignment of timing for all four utilities in the last rate case, and IUSA's realignment of its internal resources during that case, to accomplish more cross-company functionalization of rate responsibilities. IUSA has not yet sought stakeholder input on consolidation.

The one-time resources required for any rate consolidation would likely include outside cost-of-service studies and consultants. Some ongoing savings in personnel could result; IUSA could not precisely estimate them, but cited a conservative upper bound of six persons.

C. Corporate Structure – Conclusions

1. IUSA operates within a corporate-entity structure whose design can promote and support the identification of New York utility needs on a timely and sufficient basis.

- The structure of the entities does provide the ability to focus strongly on New York needs.
- The structure does promote a high level of local accountability for U.S. utility needs.
- The structure provides adequate separation of the major non-utility business in the U.S.

- The other non-utility businesses are not large.
- The structure promotes effective operation of both NY and ME utility needs.

One must examine the structure for serving IUSA's New York utility customers in the context of the share that they represent of a very large and multi-continent holding company. IUSA's utility operations comprise a very small part of ISA's business (well less than 10 percent by any measure). ISA has adopted an approach that places within each country nearly all of the resources required in that country. For U.S. operations, that means that virtually no direct operational support (as opposed to oversight and direction at a general level) comes from off-shore. The organizational structure of U.S. operations places IUSA at the top and locates within IUSA or its subsidiaries essentially all resources who contribute to providing service in New York. The Networks Group, led from Spain, exercises a substantial role in coordinating efforts to assure the use of best practices across ISA's extensive utility operations footprint, and reviews resource requirements, plans, and usage among what amount to separate utility distribution operations in Spain, the U.K., the U.S., and Brazil.

IUSA operates its New York and Maine utility businesses under a highly consolidated structure, but maintains separate dedicated state leadership for each of the two states. The recent sale of New England gas operations has narrowed the scope of operations in a manner that supports further top executive management attention on New York utility operations. IUSA has brought together what had been two service-company groups under Energy East, and now offers in common to New York and Maine a comparatively broad range of services. IUSA has also undertaken a significant level of operations consolidation, bringing a wide range of engineering, design, construction, operations, and customer-service functions under common management.

The non-utility operations managed by IUSA have been structured in a manner that, particularly given their size, complexity level and risk, and lack of expansion plans, promotes organizational and senior management focus on utility operations. ISA has essentially completely separated its largest U.S. business (Renovables) from IUSA from entity, organizational, staffing, and operational perspectives.

The conceptual underpinning of ISA's structuring of the U.S. utility businesses allows, when effectively implemented, for a structure, a management team, and the full range of resources dedicated fully to serving utility needs, with adequate attention to assuring a sufficient New York focus.

2. The way that ISA has executed its organizational approach to U.S. utility operations has led to challenges for U.S. management. *(Recommendation #1)*

Spanish leadership above the U.S. executive team has focused inordinately on staffing reductions across its early years of ownership. That focus was driven largely by benchmarking, not with U.S. operations, but largely with those of Spain. Very large reductions have occurred and their importance to ISA leadership is witnessed by the reporting to the parent board essentially every month of staffing reductions in the U.S. As noted elsewhere in this report, those reductions have continued even as IUSA has had substantial difficulty in meeting capital spending commitments.

Meeting these commitments timely and fully on a total dollar basis comprises only part of the challenge for IUSA management. Spending those dollars efficiently has equal importance. The value to customers comes not, per se, from how much is spent, but what facilities result and how they affect service quality and reliability. Impairing the ability to bring efficiently priced resources to bear under well-planned and sequenced work programs creates too great a risk of waste. Later chapters of this report treat these resource issues and work progress difficulties in more detail.

Senior U.S. management observed to Liberty that Spanish leadership has come to the realization that differences in the U.S. (*e.g.*, climate and vegetation) affect resource requirements. This realization comes at a time when the objectives of ISA include overcoming resistance in U.S. markets to retaining the ISA subsidiary (II&C), which has been successful in Europe and other regions in establishing itself as a strong competitor in providing engineering and construction management services.

3. The introduction to the U.S. of a close organizational alignment between IUSA and II&C poses great risk for IUSA, without clear, compensating advantages. *(Recommendation #1)*

II&C has for a long time served as the construction management arm for ISA's utility operations business in Spain. II&C's relationship with the Scottish utility arm of ISA is growing as well. Outsourcing utility engineering, construction, and construction management to an affiliate seeking a major third-party marketing presence is very uncommon in this country.

ISA has for several years sought to establish a platform for growing the business of II&C in the U.S. Those efforts have met with little success. Liberty believes that growth of II&C's business, both globally and particularly in the U.S. remains a key element of ISA's overall growth strategy. It has become clear that ISA views work for its U.S. utilities as an important foundation for developing the credibility that II&C needs to compete more successfully with existing U.S. engineering and construction management firms for work. Moreover, use of II&C in a near-total capacity has formed part of the European strategy for some time, with essentially all Spanish utility infrastructure work assigned to the affiliate and all Scottish work at extra high voltage levels. The reductions that IUSA has made in internal personnel increased its reliance on contractors, and therefore the opportunities for II&C. The recently appointed IUSA vice president (in his first year of a three to four year U.S. assignment) acknowledges the need for additional resources to support the planning, scheduling, and management of the major New York capital expenditure program. He feels that internal resources are at appropriate levels and that retention of contract personnel represents the correct path for providing needed additional resources. He has also expressed support for the Spanish model, which has led it to contract out the management of construction.

This confluence of circumstances poses a significant risk to the strengthening of core, internal resources that Liberty believes should comprise a priority for IUSA. The desire to grow the II&C U.S. business, using work for the U.S. utilities as a platform, will inevitably influence resources decisions, as internal hires will displace contracting opportunities. Placing the responsibility for overseeing those decisions at the executive level on an expat whose future with ISA involves a return to Spain adds additional pressure to support the affiliate's growth goals.

After a steady pattern of emphasis on reducing internal staff and increasing use of outside contractors at IUSA, ISA is now seeking a large expansion of II&C's role with IUSA. II&C has otherwise failed to establish the foothold that ISA seeks for this subsidiary in the U.S. It is clear that service to IUSA forms a primary basis for establishing market credibility for II&C, which seeks to become a major provider of engineering and construction management services to third parties.

Given the steep cuts in internal staffing, and given the recognition by senior management that measuring cost effectiveness is a work in progress at IUSA, it is particularly troubling to see the introduction now to a major role of an affiliate who has commercial objectives that are not wholly consistent with those of IUSA. Pending a comprehensive, analytically sound basis for optimizing in-house and external resources, we consider it premature to introduce the melding of resources between IUSA and II&C.

One cannot take substantial comfort from the use of II&C on a "no-profit" basis, for a number of reasons. The primary one is that, given the current state of IUSA resourcing, it is fallacious to treat the analysis as a comparison of the no-profit cost of the affiliate with the cost of a third-party provider. The best choice may well be adding an internal position, which could impose a cost far lower than either contracted alternative. In this case, that comparison becomes all the more striking when realizing that II&C will have to add staff to serve IUSA's needs. II&C only had 10 U.S. employees before beginning to address IUSA needs. IUSA acknowledges the need for establishing a more sound resource planning model and it acknowledges that its personnel cuts in the relevant areas have been too deep. It puts the cart before the horse for IUSA to extend commitments that will cause II&C to add for IUSA's benefit some of the very same resources that completion of IUSA's baseline resource planning work may cause it to determine it needs to hire internally.

Even if the cost "advantage" of II&C is considered material, several other factors make it elusive. First, as the affiliate succeeds in acquiring business from third parties in support of its growth strategy and presumably at profit, it is unrealistic to expect that its strongest resources will remain on IUSA work. Moreover, at whatever level of capability and experience the affiliate replaces resources on IUSA work, the disruption to work continuity and familiarity with the work circumstances and environment will have negative consequences. Second, II&C will have to devote time, attention, and resources to marketing, sales, and other business development activities. The resulting costs will not benefit IUSA, but IUSA will remain the only (or at least predominant) paying customer who may be responsible for them.

Senior IUSA executives observe that loss of expertise is a risk with third-party contractors as well. This observation does not take account of the fact that those contractors have a significantly greater incentive to "please" IUSA, as the loss of its business risks profit loss. Common sense dictates that a utility will hold a third-party provider to a higher standard of performance. The statement that IUSA will expect, require, and respond to performance no differently than it would for a third-party provider is not reassuring.

There also remains the question of verifying that no more than fully-allocated costs will be charged. It is positive that the affiliate will use FERC service-company accounting. That will make cost verification easier. However, if full and complete examinations occur, they will take substantial resources, and, like other affiliate costs, will likely entail periodic examination through regulatory representatives (*e.g.*, such as is the case for this audit). These activities will impose costs and, while they can mitigate the risk of improper charging, cannot eliminate it.

4. IUSA has during 2011 been actively and appropriately considering the costs and benefits of legal consolidation of the New York utilities.

The Company has completed the first phase of (and issued a report addressing) a comprehensive study of consolidating the New York utilities into a single corporate entity. It completed that study generally as and when planned. The study looked at a comprehensive range of areas that legal consolidation would affect. It did a reasonable job of identifying costs to implement and changes in ongoing costs and benefits of consolidation versus continuing to operate as distinct corporate entities, but with a high level of operational integration. Our review of the study found some areas where quantification of benefits was not as detailed as possible. On the other hand, we found a number of risk areas (e.g., in transferring franchises, property interests, licenses and permits, and other documents underlying the authority to operate utility businesses) to which no costs had been assigned.

We believe that IUSA's present conclusion that legal consolidation will produce no net benefits is a sound one, particularly given that the second phase of study work will seek to refine further the cost/benefit analysis work of the first phase. We believe that the essentially universal U.S. holding company and merger/acquisition experience buttresses this conclusion. We have reviewed analyses of costs and benefits of a number of U.S. utility mergers. None, in our experience, cited legal (versus operational) consolidation as a benefits producer. More significantly, our work extends to more than ten multi-utility holding company cases in the U.S. In all cases with which we have direct familiarity, separate legal utility entities have been maintained, in a number of cases after one or more acquisitions. Certainly, IUSA's unique circumstances are more directly relevant. However, the fact that their findings appear to be similar to those of other U.S. utility holding companies does provide some level of corroboration of IUSA's findings based on a reasonably comprehensive evaluation of its unique circumstances.

IUSA has undergone very significant operational consolidation. In our experience, it lies at the higher end of the range, in terms of the number of activities, functions, and organizations consolidated. Moreover, the phase two consolidation study work will focus on whether other opportunities of that nature remain. The second phase will also allow for further consideration of the costs and benefits of legal consolidation as may prove appropriate.

We therefore found that IUSA has appropriately been addressing legal consolidation, and continues to seek opportunities for synergies arising from further operations consolidation. We too consider it proper to hold open further consideration of potential savings from legal consolidation, but, like IUSA, we consider it unlikely that further work will contravene the conclusion that legal consolidation will not offer further, significant net cost benefits.

5. IUSA is aware of the differences in rate categories and levels, and has been appropriately engaged in efforts to address them.

We found IUSA to be cognizant of and sensitive to the differences in costs, revenue requirements, and rate structures of its four New York utility operations. IUSA has been undertaking consolidation to some degree over a number of years. Moreover, increasing centralization of services and activities has caused some merging of costs, thus reducing differences in some revenue requirements areas. Nevertheless, as reasonably complete and detailed analyses of rate differentials prepared recently by IUSA show, there remain significant differences in total revenue requirements between NYSEG and RG&E (both electric and gas). Moreover, there are even more dramatic differences between some of the rate classes of the two utilities.

IUSA continues to work toward a consolidation of tariff terms and conditions and its last rate proceedings served to place all four utilities on a common measurement basis. The Company plans to continue to assess rate consolidation. We believe that differences in total revenue requirements and in rates for certain classes make the wisdom of continuing a gradualist approach to rate consolidation not a management and operations issue, but we recognize that it has very important public policy ramifications in terms of setting cost-based rates and promoting customer acceptance.

D. Corporate Structure Recommendations

1. Suspend indefinitely the provision of services by affiliate IEP to the New York Utilities. *(Conclusions #2 and 3)*

IUSA's most important New York utility engineering and construction management priorities are not to find a contractor (particularly an affiliated one) that might (even if it were likely to be true) produce marginal savings over the costs of contractors already available in the marketplace. Those priorities are to develop and use significantly improved resource planning and cost management principles, resources, approaches and methods to restore balance to the significantly reduced level of internal staffing driven by ISA during its early period of IUSA ownership. We are not familiar in our experience with the outsourcing of core functions to a non-service company affiliate. We are for a number of reasons also not persuaded that the failure to include a "profit" in the affiliate's fees makes a significant difference. First, the affiliate will remain significantly more expensive. Second, if the resources are truly to be dedicated long term to the New York utilities, the affiliate will have to hire them just as the utilities would. Third, it is transparently unreasonable to expect that the affiliate, whose driving objectives are not to serve the utilities at cost, but to serve the market at a profit, will provide either constancy or its prime resources to the utilities.

For the reasons set forth in the chapter addressing construction program management, this recommendation will produce significant net savings.

E. Executive Organization and Leadership - Findings

1. Global Executive Organization

ISA recently created a new global business organization structure. [Note that this change was made for 2011; it is not part of or related to the February 2012 IUSA corporate reorganization announced by ISA.] The regulated utility businesses, including those of IUSA, fall under what ISA terms it Networks Business Group (Networks). The next table shows the scope of Networks' operations. The new Networks Business Group has been rebaselining network operations under an integration plan supervised by an Integration Steering Committee. The plan is not likely to be completed before 2012. IUSA is seeking to incorporate best practices it has identified into the plan.

Working Groups are carrying out the detailed work. An Integration Office is providing support. The Steering Committee's responsibilities are to:

- Approve work streams, composition, and activities of each group
- Define an operational model
- Establish a 2011-2013 Business Plan.

The committee consists of three members each from network operations personnel in Spain, the U.S., and the U.K. The chief executive of the Networks Group heads the committee. The U.S. members are the CEO, the COO, and the Vice President-Operations (the Spanish executive named to serve as co-COO of IUSA).[1] The three members from Spain are:

- CEO of Distribution in Spain; also an IUSA director
- Networks Control Manager in Spain; also an IUSA director
- Sustainability, Processes, and Technology Director in Spain.

Working Groups focus on specific, related functional sets of activities (work streams), seeking to define them, identify and incorporate best practices, seek out revenue-increase and cost-reduction opportunities, identify human and economic resource needs, and design action plans to reach the desired state of operations in their areas of focus. Each Working Group operates under a sponsor, a project manager, and members from each of the three countries where Networks operates. The next table lists the Working Groups.

Network Operation	***Smart Grid & Metering***	Health, Safety, & HR
Emergency Plans	SAP	Revenues
Eng. Standards/Major Projects	IT	Economic Processes
Asset Management	Customer Services	Risk Management
O&M & Connections	Telecommunications	Corporation Relationship

[1] IUSA, in commenting on a draft of this report, cited the term "co-COO" as inaccurate. The parent board minutes note the initial appointment of the current IUSA COO in late 2009, calling the job "a position he will hold together with" this executive assigned to IUSA from operations in Spain.

Of the 15 Working Groups, none of the leaders of network-related areas (shown in bold and italics in the list above) come from IUSA. Two IUSA executives from Spain (the IUSA CFO and co-COO) lead teams. The IUSA leaders of other teams include: (a) the sponsors for the Customer Services and Revenues teams, and (b) the project managers of the Revenues and Health, Safety, & HR teams. The Integration Office supports Working Groups by serving as an interface among the persons engaged in the efforts, and by establishing an initial set of Key Performance Indicators. The integration office consists of five Spanish employees. IUSA has also reported that a consultant is assisting in the effort, which IUSA has also termed "Networks Integration."

2. IUSA Executive Organization

a. IUSA Executive Team

IUSA operates under a 24-person executive team (persons above Salary Grade 10). Two Spanish executives serving as officers in the IUSA organization do not show on the executive list IUSA provided: (a) the executive named some time ago as co-COO of IUSA and still serving IUSA, and (b) the CFO.

IUSA Executive Team

Iberdrola USA Management Corporaton		NYSEG/RG&E	
Chief Executive Officer	Kump	President	Lynch
Chief Operating Officer	Walker	VP, Controller & Treasurer	Syta
SVP Transmission Business Development	McClain	Vice President - Gas Operations (NY)	Eastman
Vice President - Electric Operations	Jensen	VP - Energy Supply/Transmission Services	Kimiecik
Vice President - Eng & Asset Management	Smith	VP - Rates & Regulatory Economics	Lahtinen
VP - General Counsel	Connolly		
Deputy - General Counsel	Mahoney		
Deputy - General Counsel	Dolan	**Central Maine Power**	
Controller - Accounting	Call	President & Chief Executive Officer	Burns
Controller - Taxes	Gentile	VP - Customer Service (ME)	Cowan
Vice President - Human Resources	Lamoureux	Vice President - Special Projects	Herling
Vice President - General Services	Reynolds	VP-Controller-Treasurer and Clerk	Stinneford
Vice President - Business Transformation	Taylor		
VP - Regulatory Strategy	Adams		
VP - Information Technology	Ballard		

b. IUSA Vice President – Operations

The Spanish executive named in late 2009 as co-COO with the U.S. officer named to that position essentially contemporaneously now shows as an IUSA Vice President – Operations, reporting to the IUSA CEO. No positions report to this IUSA executive. His position has no formal job description. IUSA describes his job as supporting the IUSA operations team "by providing his many years of expertise and knowledge of the practices and procedures of the Iberdrola Group." This officer, for whom IUSA created the position, has been with Iberdrola since 1975; he has been engaged in a wide variety of positions in electric transmission and distribution in Spain across this period. During his last 10 years in Spain he had responsibility for ISA's Madrid distribution business, which serves 2 million customers and a population of 4 million.

c. IUMC

IUSA created Iberdrola USA Management Corporation (IUMC) on January 1, 2010. Organization charts for the preceding year are not available; however, there follows a listing indicating the positions and staffing levels within each respective department and cost center. IUMC replaced two groups, which were known as Energy East Management Corporation (EEMC) and Utility Shared Services (USS). IUMC's creation resulted from the merger of EEMC into USS, and a name change from USS to IUMC. IUSA has described the consolidations from IUMC creation as coming in the Accounts Payable, Accounting, Tax, and Treasury and Finance departments, where resources had been split between EEMC and USS.

IUSA considers the organization of IUMC now to be stable; no further reorganizations or staffing consolidations are planned for the near term. Recognizing, as noted elsewhere in this report, that IUSA's phase-two consolidation study will be examining further organizational consolidation to promote efficiency. IUMC staffing as of April 2011 is 365, compared with the 404 shown in the following two tables. Staffing at NYSEG at this time was 1,947, and 837 at RG&E. These tables summarize EEMC and USS organization and staffing prior to IUMC creation.

Former EEMC Staffing

Cost Center	Staff	
	Notable	Total
IUSA Executive	CEO; COO; CoB/CEO; Flight Director	7
General Counsel	VP/General Counsel; Director-Compliance	5
Human Resources	VP-Human Resources	4
Public Affairs	Executive Administrator	1
Transmission/Energy Supply	Manager-Energy Supply Risk	1
Internal Audit	Director-Internal Audit	12
Controller	Controller; Director-Corporate Finance	27
Finance	SVP/Chief Development Officer; Director-Risk Management	6
Regulatory	VP-Regulatory Policy	4
Administration	SVP/Chief Administrative Officer	1
	TOTAL STAFFING	***68***

Former USS Staffing

Cost Center	Staff	
	Notable	Total
Talent Management	Mgrs for Shared Services and Payroll/Administration	17
Env/Health/Safety	Director-Compliance	2
IT	VP-IT; various IT and communications managers	162
Supply Chain Services	VP-Supply Chain; Dir-Strategic Sourcing; Mgr-Fleet Services; Dir-Materials Management; Dir-Store Operations	46
Accounting	Controller; Dirs for Plng/Rprtg, Gen Acctg, Acctg Services,; Mgrs for AP, Continuous Improvement, Acctg/Analysis, Regulatory Acctg, Cost Acctg, Income Taxes, Local Taxes	101
Claims Management	Lead Analyst	7
IUSA Executive	VP Business Transformation	1
	TOTAL STAFFING	***336***

d. IUO

The recent change to a matrix approach to what IUSA calls "front-office" operations has produced a group termed IUO (Iberdrola USA Operations). The IUSA COO was not familiar with this organization. A document titled *Iberdrola USA Operations Service Level Measures 2011*[marked as a November draft] describes the services that IUO provides to each of the three U.S. operating utilities, categorized by the functional areas of service:

- **<u>Customer Service</u>**
  - Delivery of service and processes
    All forms of customer contacts *Minimizing complaints* *Issuing bills*
    Account data quality *Cash collection/debt management* *Collection of meter reads*
  - Management of commercial risk
    Minimize debtor days/ debt write-off *Meet regulatory service targets*
    Meet NY energy efficiency targets *Manage low-income programs*
  - Cost reduction with service quality improvement
    Migrate customers to lower cost (e-billing/direct debit) *Rapid results projects*
    Improve labor agreement costs *Manage discretionary costs* *Continual IT upgrades*
  - Delivering "excellence in Customer Service"
    Improve customer satisfaction scores *Increase media and community presence*
    Improve relationships with key stakeholders
- **<u>Electric Distribution</u>**
  - Safety
    Routine safety tailboard briefings *Re-briefings upon scope change*
    Collaboration with ES&H *Safety Scorecard measures to supervisory level*
  - Reliability
    Meet SAIFI/CAIDI targets *Improve worst performing circuit reliability*
    Monitor CAIDI measures at service-center level *Manage recovery efforts*
  - Cost
    Reduce cost/improve quality *Improve labor agreement costs*
    Meet O&M OPEX targets *Centralized Line/Field Planner Dispatch/Scheduling*
- **<u>Gas Distribution</u>**
  - Strategic planning and functional oversight for the gas field operations
  - Emergency response and mandated O&M inspections
  - Mandated highway replacements and new business construction
  - Systematic replacement construction programs
  - Coordination with supply, control, marketing, engineering and asset management
  - Assist in and oversee budgets and monitor contractor work performance
- **<u>Engineering and Asset Management</u>**
  - Electric System Planning
    System modeling & analysis *ISO Coordination (NY and NE)*
    NYISO system planning/ CMP Local System Plan *NYPA Power Program Contract & Billing*
  - Asset Management and Investment Planning
    Develop capex and maintenance plans *Maintain capex order book process*
    Administer GIS, maintain mapping, master data and engineering records
  - Electric System Engineering
    Designs and cost estimates *Const. standards, material specs, approved materials*
    Electric and gas meter testing, inventory *Safety equipment and PPE testing*
  - Electric Capital Delivery
    Project cost and schedule management *Coordinating material procurement*
    Acquiring construction resources *Construction management services*

- Electric Maintenance Delivery
  Manages Vegetation Management Programs *Regulatory and Reliability Reporting*
  Develop/implement substation maintenance programs
- Gas Engineering & Delivery
  Design and cost estimates *Corrosion Control* *Emergency/Integrity Mgmt. Plans*
  Capital Project/Program Delivery *Const. standards, material specs, approved materials*

- **General Services**
  - Materials Management (also serves non-utility operations, beginning in fourth quarter of 2010) (note: the IUSA COO was not familiar with the non-utility aspect of the group's operations)
    Material Planning *Inventory control* *Logistics*
  - Fleet Services
    Preventive Maintenance *Demand repairs* *Acquisition/disposal*
    Fueling systems/programs *Collision management program*
  - Real Estate and Facilities Management
    Manage title docs *Organize ROWs* *Joint use/encroachment agreements*
    Negotiate/manage leases *Keep records, surveys, maps* *Operate facilities*
- **Information Technology**
  - Productivity: Support productivity of clients through applications required, IT Service Desk calls for IT assistance, etc.
  - Operations: Printing and mailing of bills, nightly processing of batch jobs, including cash uploads, meter read uploads, bill file creation, etc.
  - Business Solutions/Application Development: Production application support and projects (e.g., SAP CCS)

e. IUSA Staffing

The next two tables compare staffing at 2010 end, following IUMC creation, and as of April 2011.

Year-End 2010 IUSA Staffing

Area	Entity									
	CMP	MNG	NHG	NYSEG	RGE	IUMC	ENET	ENX	TEN	TOTAL
Business Transformation	-	-	-	1	4	2	-	-	-	**7**
Customer Service	254	-	-	535	233	-	-	-	-	**1,022**
Electric T&D	426	-	-	803	269	1	-	-	-	**1,499**
Engineering & Asset Mgmt	101	-	-	169	62	3	-	-	-	**335**
Finance	-	-	-	-	-	131	13	25	29	**198**
Gas	-	6	8	190	141	-	-	-	-	**345**
General Services	46	-	-	118	36	24	-	-	-	**224**
Human Resources	21	-	-	25	29	26	-	-	-	**101**
Information Technology	13	-	-	8	1	157	-	-	-	**179**
Internal Audit	-	-	-	-	-	9	-	-	-	**9**
Regulatory	10	-	-	9	12	3	-	-	-	**34**
Transmission Services	-	-	-	-	-	1	-	-	-	**1**
Office of CEO	2	-	-	1	3	13	-	-	-	**19**
CMP President	31	-	-	-	-	1	-	-	-	**32**
NYSEG & RG&E President	-	-	-	67	42	1	-	-	-	**110**
Grand Total	**904**	**6**	**8**	**1,926**	**832**	**372**	**13**	**25**	**29**	**4,115**

April 2011 IUSA Staffing

Area	Entity									
	CMP	ENX	IUMC	MNG	NHG	NYSEG	RGE	TEN	ENET	TOTAL
Business Transformation			2			1	3			**6**
CMP President	31		1							**32**
Customer Service	277					589	248			**1,114**
Electric T&D	428		1			807	264			**1,500**
Engineering & Asset Mgmt	78		5			133	57			**273**
Finance		24	131					29	13	**197**
Gas				7	8	195	139			**349**
General Services	45		22			122	35			**224**
Human Resources	18		26			23	27			**94**
Information Technology	12		148			1	1			**162**
Internal Audit			9							**9**
NYSEG & RG&E President			1			67	45			**113**
Office of CEO	2		15			1	3			**21**
Regulatory	9		3			8	15			**35**
Transmission Services			1							**1**
Grand Total	**900**	**24**	**365**	**7**	**8**	**1,947**	**837**	**29**	**13**	**4,130**

f. Maine and New Hampshire Gas Operations

Remaining gas operations in the New England states (Maine and New Hampshire) operate with small direct staffs. The personnel dedicated include:

- Maine - headed by Vice President
  - Supervisor of Gas Operations
    - Three technicians

  - Representative - Accounting Clerk
  - Representative - Customer Service
- New Hampshire
  - Gas Service Supervisor Technician
    - Meter Technician
    - Gas Service Technician
    - Customer Service Representative
  - Distribution Supervisor
    - Lead Analyst – Accounting
    - Plant Operator
    - Assistant Plant Operator
    - Two Seasonal Laborers.

F. Executive Organization and Leadership - Conclusions

6. The IUSA organization and executive structure appropriately focuses on New York utility needs and promotes efficiency through a notable level of consolidation of functions performed in common for U.S. utilities.

The structure provides for a single executive in charge of U.S. operations, consolidates operations functions under a COO position, and provides for state presidents for New York and for Maine. The structure and sizing of the organization are defined predominantly by utility needs. IUSA has undertaken consolidation of the "back-office" functions typical of multi-utility, multi-state operations. IUSA has been consolidating the front office and field functions; we find its level of consolidation to be notable in our experience. Moreover, as part of the current consolidation study (addressed earlier in this report), IUSA continues to seek further opportunities to combine commonly performed utility functions.

Apart from the matter of ISA's engineering and construction affiliate (II&C and its subsidiary IEP), also addressed earlier in this report, IUSA's executive focus is predominantly on utility operations. The other major ISA operation in the U.S. (Renovables, which is a major participant in the U.S. wind generation business) operates with its own organization and resources and from different locations.

7. IUSA's dispersal of functions key to the operation of its gas business is unsound, given the circumstances here. *(Recommendation #2)*

The key elements of the gas business are dispersed among a number of executives. Technically, the same can be said of the electric business, but it is clear that the common organizations are led by persons not only whose predominant background and focus is electricity. Moreover, ISA's experience, including that of the three Spanish executives placed in IUSA's executive organization are the same. ISA does not focus substantially on gas distribution in other countries, and its disposition of the New England gas companies was described as resulting in significant part from the fact that gas-only distribution is not considered a core business; *i.e.*, gas distribution fits with ISA's core strategy only where it can be conducted in geographical tandem with the core electricity-distribution business.

The natural gas business of IUSA, particularly following the disposition of the New England gas LDCs is small by comparison with the U.S. electric business. A fairly common problem in the past for U.S. combination companies has been a failure to give gas the same visibility in the organization. Natural gas operations have distinct requirements and meeting them requires substantial clout within the organization. Capital and operating needs are different in nature gaps in meeting them would have different public consequences. Particularly in an environment that has strongly emphasized staffing reductions, it is necessary that unique gas needs be championed at the top levels of the organization. Otherwise, apportioning budgets, staffing cuts, and other resources risks becoming too much the norm. A more substantial inclusion of executives with a greater predominance of gas experience throughout the executive team might serve, but that is not the case at IUSA.

We made a number of observations relevant to the lack of a consolidated organizational approach to the gas business. The Supply Procurement - Gas chapter noted that the reporting of gas supply personnel comprises another area of concern in this regard. Our concerns about staffing were broadly applicable to IUSA. We found them particularly common for the gas business. The asset management and delivery organizations are both headed by persons without significant gas experience. One had been with the affiliated Maine utility, which has nominal and recent gas operations; the other a newly created vice president assigned to the IUSA organization from Spain, where his work focused on electricity. Interestingly, the CEO explained the rationale of combining electric and gas resources in asset management, engineering, and construction management as allowing synergies through the use of resources who can work in both businesses. A review of the organization charts and staffing, confirmed by the head of the combined engineering and construction management resources demonstrates that there is no overlap of resources; *i.e.*, the electric and gas businesses have their own dedicated leadership and resources.

Questions about resource levels, the level of natural gas experience at senior executive levels, and the lack of complete clarity on the rationale for the gas business's structure indicate to us that the long-term ability to meet gas business needs merits additional organizational focus at the top levels of IUSA.

8. The IUSA executive team does not convincingly exhibit the hallmarks of a fully empowered and fully synchronized group. *(Recommendation #3)*

ISA has made many changes at the top levels of IUSA executive management since the end of Energy East's stewardship of the New York utilities. Not only did Energy East employees take new, more senior positions at IUSA, but many especially senior positions went to people totally new to IUSA; *e.g.*:

- New U.S. employees as COO and New York President
- New Spanish employees as co-COO and CFO
- European employees brought on to fill other vice presidential positions (a Scottish employee in customer service and a Spanish employee in engineering, design, and construction management).

On top of these changes, ISA assigned for the first couple of years of its stewardship the head of its international businesses as the senior Spanish executive responsible for oversight of IUSA.

This Spanish executive's role was more than nominal, [redacted]. This executive's decisions included the choice of [redacted]. In reverse order to what one would normally expect, the COO and the New York President decisions were made before the decision on the CEO, despite the fact that the other two would be perhaps his most critical team members. The decisions [redacted] to bring on Spanish-based CFO and co-COO executive team members stands as unusual, referencing the [redacted]. The fact that the CEO, while a former Energy East employee, was also new to the CEO position meant that the group was essentially all new to their positions, and, but for the CEO, new to the IUSA.

A lack of immediate cohesion is to be expected under such circumstances. That understanding, however, does not mitigate the need for the formation and nurturing of a cohesive team operating under a strongly empowered top-leadership team. The nature of ISA's creation of and interaction with the U.S. team has created barriers in this regard.

ISA leadership in Spain has repeatedly observed that local issues are left to local management. However, it is clear that among "local" issues do not include much leeway in selecting key executive team members. In addition, it did not include leaving to local management decisions about necessary local resources. It has been made clear to us that major staffing reductions during the early ISA stewardship were driven by views in Spain about how U.S. staffing compared with that of European operations.

Spanish leadership's views have many avenues of expression at IUSA. The IUSA board is dominated by senior ISA executives from Spain. Network operations personnel (some working today directly for others in their management positions) have particularly strong representation. The many Working Groups seeking to identify and establish common best practices among all network companies across the continents served by ISA are, particularly in operations areas, led by European (particularly) Spanish personnel.

Dispersed working locations adopted by IUSA's executive team are likely to have contributed to difficulties in moving the IUSA team quickly and effectively to the state that we consider typical of effective utility management; *i.e.*, a strongly empowered CEO leading a diverse, but dedicated and supportive senior team. The particular locational features of interest include:

- The CEO's principal base is in Maine; he is joined there by the CFO assigned from Spain to the IUSA executive team
- The Spanish co-COO operates from Rochester; note that he reports to the Maine-based CEO
- The General Counsel works from Boston; his office mate is a Spanish executive assigned as the "governance" specialist for all of the Americas (*i.e.*, not just U.S. utility operations)
- The New York President operates from yet another location; *i.e.*, Albany.

Certainly, communication among them is regular and common, and often from the same locations. However, we note the following circumstances:

- No substantial history working together or even in their current positions

- Multiple means for senior Spanish executives, who do not spend much time in the U.S. to engage the IUSA executive team
- The CEO, COO, and General Counsel all have senior, Spanish personnel co-located with them
- The history of involvement from senior ISA executives in U.S. executive selection and staffing reductions (not easy to square with the stated ISA policy of leaving local matters to local management)
- That it took until the spring of 2011 to place the IUSA CEO on the IUSA board.

These circumstances, at the very least, cloud the ability to conclude that the IUSA executive team operates with the empowerment, power distribution, and cohesion one would expect, were IUSA a stand-alone utility. Adding to this complicating factor is that reliance on temporarily assigned European executives can create discontinuities in approach and organizational performance. The potential for fairly abrupt departures of such executives from the U.S. is not only hypothetical. The Scottish head of IUSA customer service returned to an executive position with ISA in Europe on what, at least as visible to us, was very short notice. Another key IUSA vice presidential position held by a Spanish executive manages engineering, design, and construction management of the expanded IUSA capital program. Placing him in that position may in the short run solve some of the problems that IUSA has had in meeting Commission-mandated expenditure levels in an evenly paced (and therefore optimally efficient manner). The two less sanguine aspects of the assignment, however, are that:

- Placing a temporary person in a position where even the Company acknowledges need for improvement (and which we believe to comprise a significant management gap) does not augur well for creating the stable, engaged leadership it will take to bring performance to high levels on a sustained basis
- Placing a Spanish executive in this position when the goals of leadership in Spain (which prudence dictates is where we should assume that the executive's long-term future with ISA lies) include developing a major third-party, market presence for the affiliate places IUSA's interests at undue risk.

Within the environment created by circumstances and dynamics such as these, we observed a number of factors that may bear on the degree to which the IUSA team has been given adequate opportunity to coalesce around a model that will strongly serve U.S. interests:

- Changing positions on access to audit preparation documents
- What we perceived as a gap in understanding between U.S. and Spanish management about access to materials and interviewees in Spain
- Lack of senior IUSA executive's familiarity with certain elements of operations reflected in formal material provided in response to audit requests:
  - Lack of familiarity with an organization, known as Iberdrola USA Operations, that appears to have assigned service responsibilities to U.S. utility organizations and documented service level metrics (i.e., Iberdrola USA Operations Service Level Measures)
  - That the Materials Management organization serves not only utility, but non-utility operations
- The CEO's proffered rationale for the assignment of key gas business functions to combined electric/gas organizations

- The contrary expressions of how the IUSA executive compensation program works and what decisions in Spain have to do with it
- Substitution of personnel and failure to meet expectations when scheduling sessions to address benchmarking IUSA with other U.S. utility organizations.

9. IUSA executives are fully engaged on and aware of New York conditions, needs, priorities, resources, customer needs, and public requirements and expectations.

We have elsewhere addressed the engagement and knowledge of parent board members and executives in Spain, where significant gaps exist, by comparison with what we have seen at other, U.S.-based holding companies. We distinguish substantially the situation with respect to IUSA executives and senior managers. They exhibit the detailed knowledge of their areas of responsibility that we would expect. Elsewhere in this chapter we address the issues of empowerment and cohesion in the IUSA executive team and the risks and distractions that we believe come with Spain's efforts to embed IEP into the IUSA structure.

10. The IUSA board has not undertaken structured and regular self-assessments of top IUSA management. *(Recommendation #4)*

Structured and measurable performance objectives exist for the CEO and all officers and senior managers. IUSA regularly measures performance against them, and uses measurements to set incentive compensation. The IUSA board, however, has not undertaken formal reviews of CEO performance with the incumbent. As noted in the governance portion of this report chapter, there have been concerns about the IUSA board (which has no compensation committee) role in executive compensation determinations and with Spain regarding the establishment and significance of global performance metrics that were intended to apply to U.S. incentive compensation.

G. Executive Organization and Leadership – Recommendations

2. Consolidate the gas business under a single executive reporting to the COO. *(Conclusion #7, Chapter VII Conclusion #2, Chapter IX Conclusion #4, #15, #17)*

The structure of IUSA's resources already largely places gas planning, supply, engineering, design, construction management, and operations resources under dedicated leadership. IUSA should consolidate these groups by moving them to an executive who will then report to the COO. This change will bring together key gas functions under a senior official who is dedicated to the gas business exclusively. Back office and customer service functions can effectively remain where they are located at present; however, the new gas executive should be charged with monitoring and measuring service cost, quality, and reliability as provided to the gas business. A strongly empowered gas business champion is important in assuring that the gas business optimizes its focus and receives the resources it needs to thrive.

Given the nature of the existing organization, we do not believe that making these changes would entail significant costs. The primary benefit of making the change is as embodied by and expressed in the more specific recommendations found in other report chapters regarding the IUSA gas business (*e.g.*, 4, 7, 9, 12, and 13).

3. **Streamline executive communications links and focus IUSA leadership under a more fully empowered CEO, emphasizing U.S. operation's needs.** *(Conclusion #8)*

IUSA does not have a long-tenured, highly experienced leadership team operating in a stable environment. ISA emphasizes the independence of local management to make local decisions, but has created a structure that enables many different types of formal and informal influence from senior Spanish leadership. Major efforts to establish best practices, an extended period of force reductions (based in major part on Spanish leadership's use of European experience to benchmark U.S. staffing), and the current effort to "embed" affiliate IEP into IUSA's engineering and construction management organization have increased uncertainty.

Leaving local operations to local management will be far better served by empowering the IUSA CEO to act in a capacity more typical of electric utility CEOs. The incumbent has not had the opportunity to build his own team, the team he has operates with a number of Spanish counterparts, he was left out of a direct governance role until April 2011, and he faces the need already to have addressed and to address in the future the return of expatriate executives to positions in Europe. Moreover, the strong operations backgrounds of many of the European IUSA board members, considering the tendency to benchmark U.S. operations against ISA's European operations, further complicates the ability to address key current challenges (such as addressing the balance between employee and contract resources and providing for a more evenly paced and therefore efficiently executed accomplishment of the major capital program being carried out under Commission mandate). More empowered and strongly operations-focused senior IUSA executive leadership would have served and will serve better to address such challenges.

ISA needs to trim communications lines and reporting (formal and informal) to consolidate responsibility and accountability (and the full power to fulfill them) under a U.S. CEO. That is nominally how the organization looks on paper and how it is described by ISA and IUSA leaders. We believe, however, that in practice it is undercut by the many avenues of influence that exist between the U.S. and Spain and between individual U.S. leaders and Spanish counterparts.

We see no substantial implementation costs for this recommendation. Over time, we would anticipate that it can reduce top level positions by two or three, which would produce savings in the range of $1 million per year.

4. **Institute formal IUSA board evaluations of CEO performance and review of CEO evaluations of other top management incumbents.** *(Conclusion #10)*

Best U.S. practice is to conduct structured evaluations of CEO performance. These evaluations take many forms and are usually part of a board organization structure (*e.g.*, a compensation committee, a lead director). The composition of the IUSA board (should it not be fundamentally altered) will tend to make these evaluations less valuable (*e.g.*, the current IUSA board chair is effectively the person to whom the IUSA CEO reports on a functional basis; at least one IUSA board member reports directly in his executive position in Spain to the IUSA board chair). There are no material costs to implementing this recommendation. The benefits will not be large if there is no IUSA board restructuring, but otherwise come from the creation of a regular and reflective opportunity for the CEO and the board to identify relationship, process, communication, and other improvement opportunities on a continuous basis.

H. Governance - Findings

1. Global Governance

a. Structure and Controls

ISA operates under a comprehensive "Corporate Governance System," which the parent makes available on its web site. The elements of this governance system comprise the:

- By-Laws
- Corporate Policies
- Internal Corporate Governance Rules
- Other specified internal codes and procedures.

Recognizing the international character of its operations, ISA seeks to maintain a continuously updated governance system that considers good-governance practices "generally recognized in international markets." The "General Corporate Governance Policy of Iberdrola, S.A." (dated September 27, 2011) provides an overview of this governance system. ISA has based its system in major part on the "Unified Code on Good Corporate Governance of Listed Companies," approved by the Spanish securities exchange commission (the "CNMV") in 2005, with regular consideration given to subsequent trends and developments. The ISA policy document begins by expressing the principles designed to guide corporate governance, ethics, and social responsibility:

- Adoption of a Corporate Governance System taking into account trends generally recognized in international markets
- Application of a governance strategy seeking sustained maximization of ISA's economic value of the Company and long-term success, taking into account stakeholder interests in the areas where the Company acts
- Exercise by shareholders of their ISA-related rights and performance of their responsibilities with loyalty, good faith, and transparency, placing corporate interests above personal ones
- Maintenance of a majority of independent directors on the board, and filling board committees with external directors
- Endeavors to assure gender diversity on the board, its committees, and other "bodies of the Company"
- Application of processes and procedures necessary to identify and resolve conflicts of duties and interest
- Application of a business model that separates management responsibilities between central strategy development and monitoring at the "Group" level and decentralized executive management of the group's diverse companies, while supporting global business integration and application of best practices among those companies
- Recognition of established commitments concerning the legal and functional separation of regulated companies, guaranteeing the independence of their leaders in day-to-day management of those companies

- Availability to shareholders and investors of information relevant to operating ISA and the group of companies comprising it, supplementing regularly published reports with website posting of information of interest to the markets and the public to promote transparency
- Assuring directors and senior managers who are respectable, capable, expert, competent, experienced, qualified, trained, available, and committed
- Operating, through the board's Nominating and Compensation Committee, an annual evaluation of director and committee members
- Designing and applying director and senior manager compensation policies that seek to promote motivation and loyalty, and that apply objective evaluation performance in meeting ISA goals and those of the individual Group-member companies
- Encouragement of informed shareholder participation General Shareholders' Meetings and support for their exercise of shareholder powers
- Delegation of institutional leadership, promotion of development initiatives and projects, and proper operation and improvement of the governance system to the board's Chairman.

The ISA board members Liberty interviewed have universally described the parent board's role as determining, supervising, and monitoring general guidelines applicable to the parent and to the Group, leaving to "management decision-making bodies and to the Senior Managers the dissemination, coordination and general implementation of the Group's management guidelines."

The board must meet a minimum of 11 times each year, with the board empowered, subject to change by the Chair, to set the regular meeting schedule. An independent lead director, chosen by the board may call special meetings, request the inclusion of special agenda items for board meetings, meet informally with the other independent directors, voice their concerns, and direct evaluations of the Chair. The lead director at ISA is a very capable individual, who demonstrates ample leadership skills. By comparison with U.S. companies, her role is not as strong as we have observed at other enterprises.

ISA has adopted a specific corporate and governance structure that addresses its widely dispersed and varied operations. The parent board, representing "the controlling company within the Group," has the responsibility to establish overall Group management policies, strategies, and guidelines. The parent board supervises development of strategies and guidelines, and decides matters of "strategic significance at the Group level." The board's Chair, CEO, and management team organize and coordinate the Group, and adopt and implement management policies and guidelines at the Group level. ISA's subholding companies, such as IUSA, have "decentralized executive responsibilities" for exercising "day-to-day" management and control of the groups within them. The Group "Business Model," which governs decentralized, day-to-day management at the subholding company level:

- Seeks global integration of the businesses within the subholding companies
- Maximizes operational efficiency through best-practice exchange
- Includes an "Operating Committee," consisting of the most senior executives at ISA in Spain, to provide to all the subholding companies "technical, information and management support" extending to

- Defining, supervising, organizing, and monitoring of general guidelines adopted at the parent level
- Strategic planning within each subholding company.

More particularly described ISA board duties include:

- Conforming Group structure to the requirements of the jurisdictions in which ISA operates
- Providing for the required separation of utility and non-utility activities
- Making appropriate provisions for related-party and conflict-of-interest situations
- Approving creation or acquisition of interests in special purpose entities or entities
- Seeking approval at a General Shareholders' Meeting of the assignment to dependent entities of core activities.

Each subholding company, operating within the general strategies endorsed by the parent board, has responsibilities for the day-to-day management of their subgroups through their management decision-making bodies. Each has a separate board of directors. These separate boards must include independent directors (of unspecified number or proportion). Each subholding company also has within its board a separate audit committee and within each subholding company management structure a separate Internal Audit function.

The subholding-company boards, including that of IUSA:

- Generally consist predominantly of senior ISA (Spain-based) executives dispersed among the various subholding companies
- Have a small number of independent directors (*e.g.*, two in the case of IUSA)
- Have their own, separate audit committees
- Have separate internal audit groups reporting to those audit committees
- Have no other committees.

The parent board's Chair may establish "Territorial Committees." They do not operate as governance or executive bodies, but may serve as external advisory sources to enhance information and knowledge of the particular characteristics of areas where ISA operates. The subsidiary boards and executive management in Spain and Scotland, but not in the U.S., have operated with the support of such advisory groups. The ISA CEO has ascribed the existence of such committees in Europe to the fact that top management "is not there" in a geographical sense. Top ISA management operates principally from Madrid and from Bilbao. Spain and Scotland (like IUSA) all use management and operating personnel widely dispersed throughout their serving regions. Thus, while ISA values such an outside voice even from locations much closer to its "home," it has not made a strong commitment to structured, independent input in the U.S., where it operates much farther geographically and much further culturally away.

b. Parent Board Composition

The ISA board must have between 9 and 14 directors, falling into four categories:

- Executive: Senior officers or employees of the company or of an associated group or company (sometimes termed "Internal" directors
- Proprietary: Those whose board seat arises from being or representing shareholders

- Independent: having no personal or business connection with the company, shareholders or management
- Other External: Rare cases where those qualifying as non-executive and non-proprietary, but having some connection that affects independence.

The Nominating and Compensation Committee of the board proposes candidates for appointment as Independent directors, and classifies all members into the four applicable categories.

The parent board has responsibility for assuring that external directors comprise the "large majority" of the board, and that executive (*i.e.*, not external) members are at "the minimum number necessary." The board also has responsibility to maintain a "proper equilibrium" between the two external classes of Proprietary and Independent Directors; *i.e.*, seeking to maintain the number of Proprietary in proportion to the share capital that their principals own. There is a preference for limiting the number of Independent directors with more than 12 years of uninterrupted service as directors to less than half the board. The next table shows the composition of the parent board.

ISA Board Members and Principal Backgrounds

Director	Age/Year	Background	Director	Age/Year	Background
Sanchez Galan[1, 5, 6]	61/11th	Engineering, Business[2]	Oriol Ibarra	49/6th	Finance, Control[2]
Urrtutia Vallejo[3, 6]	69/34th	Economics, Law, Business	Macho Stadler[6]	52/6th	Teaching (Econ)
Alvarez Isasi[5]	71/22nd	Teaching (Eng), Gov't, Finance	Medel Camara	64/6th	Banking
Berroeta Echevarria[5, 6]	72/19th	Industrial, Banking	Olivas Martinez[4, 6]	58/5th	Banking
Miguel Aynat[5]	67/9th	Banking, Law	Barber	42/4th	Corp. Responsibility
Battaner Arias	70/8th	Banking, Finance	Antolin Raybaud	45/2nd	Industrial (G&A)
Irala Estevez[4, 6]	65/7th	Industrial, Banking	Martinez Lage	65/2nd	Law

[1]Board Chair [2]Iberdrola Employee [3]Board Vice Chair [4]Proprietary Director [5]Committee Chair [6]Executive Committee

Apart from the Chair, board leadership averages over 20 years of tenure; average age is 61. The board members have served on a number of the same boards, as the next table summarizes.

ISA Governance Positions in Common

Institution	Business	Common Directors
Bilbao Bizkaia Kutxa	Banking	3
Cotec Foundation	Technological Innovation	3
Confederacion Espanola de Cajas de Ahorro	Banking	5
Circulo de Empresarios	Economic Development	2
Enagas	Natural Gas Transportation	3
Bancaja	Banking	2
GE	Industrial	2
Guggenheim	Museum	3
Unicaja	Banking	2

c. Parent Board Committees

The ISA board has four committees:

- *Executive*: Described as a "basic corporate governance instrument," meets as determined by the committee chair, but at least 20 times per year and further, as requested by at least two of the committee's members; reports to the next full board meeting on matters the Executive Committee dealt with and the resolutions the committee adopted
- *Audit and Risk Supervision*: Comprised of non-executive members, charged with supervision of internal controls, risk-management activities, Internal Audit (functionally controlled by the committee), outside auditor independence and activities, and process for preparing economic and financial information
- *Nominating and Compensation*: Advice and offering of proposals regarding board and committee composition, appointment of senior managers, evaluation and removal of directors and senior managers, and compensation of directors and senior managers
- *Corporate Social Responsibility*: Promotion of strategies addressing corporate social responsibility, sustainability, reputation, and governance, and supervision of compliance with the Corporate Governance System.

Internal Audit reports functionally to the ISA Audit & Risk Supervision Committee chair. ISA Audit & Risk Supervision Committee duties relative to Internal Audit are to:

- Ensure Internal Audit's independence and effectiveness
- Approve Internal Audit's plans, ensuring focus on significant risks
- Receive periodic information regarding Internal Audit activities
- Verify that senior management takes into account Internal Audit report conclusions and recommendations
- Ensure that the Internal Audit Area has sufficient resources and staff.

Membership on the ISA Audit & Risk Supervision Committee until recently consisted of three directors, having the following backgrounds:

- *Sebastián Battaner Arias Committee member since 2006; Chair until October 2010*:
  - Age 70
  - ISA director since 2004
  - Education in law and economics and practicing attorney
  - Former chair of investment, leasing, insurance companies
  - Member of the board of Ibermutuamur and various foundations in Spain
  - Former director of two Spanish banking associations, Ultralita (a Spanish building materials company operating internationally), and several foundations.
- *Ricardo Álvarez Isasi, Former Committee Secretary; no longer Committee Member*:
  - Age 71
  - ISA director since 1990, ISA Audit & Risk Supervision Committee chair from its inception through 2007
  - Professor of electrical engineering at Spanish universities
  - Former director of CADEM (government-owned, conducting technical energy-conservation studies), director of the Basque Energy Regulatory Authority, director of Iberduero, S.A. (Bilbao-based producer and distributor of electricity, and General Executive Secretary of LABEIN (a non-profit technology research center).

- *Julio De Miguel Aynat Chair since 2010,* Audit & Risk Supervision Committee *Member since 2006*
  - Age 67
  - ISA director since 2003
  - Education in law
  - Former Chair of three Spanish banks (BANCAJA, Banco de Valencia and Banco de Murcia)
  - Member of: the advisory board of Cierval (an organization that represents and defends employers in the Valencia region of Spain), the advisory board of the Spanish Institute of Financial Analysts, the board of governors of Feria Muestrario Internacional de Valencia (an institution organizing trade fairs in Spain)

Since October 2010, the Committee has consisted of three persons trained in the law. The former Committee Secretary (still a parent board member) left the committee; he was replaced by another director having the following qualifications:
Santiago Martìnez Lage *Current Committee Secretary*:

- Degree in Law from Universidad de Madrid and a career in diplomacy, from which he is currently on leave
- Served on the board of subsidiary Renovables from 2007 to 2010
- Secretary of the Board of Directors of the Spanish operations of SKF (the world's largest manufacturer of bearings and seals)
- Served on other boards: Fujitsu Services y Telettra España (telecommunications equipment)
- Former secretary of Empresa Nacional Elcano de la Marina Mercante (a 27-vessel shipping company)
- Founder of law firm specializing in European Union and Competition Law
- Member of the 33-member board of directors of Círculo de Empresarios, a Spanish, national, non-profit group promoting free enterprise.

d. Parent Board Meetings

The ISA board met 11 times in 2009 and 12 times in 2010. It continued the roughly one-meeting per month pace through the first part of 2011. All meetings have been in Spain, except for one Scotland meeting in May 2009. The next table shows Committee meetings, which have been generally consistent with timing and location of full board meetings, and which continue on a similar pace for 2011. In addition, the newly formed Social Responsibility Committee met in November and December of 2010.

Committee	2009	2010	Committee	2009	2010	Committee	2009	2010
Executive	21	20	Audit & Compliance	12	10	Nominating & Compensation	8	6

Note that the Executive Committee regularly meets many more times than does the full board and that it failed to meet at the time of full board meetings only twice during 2009 and 2010.

2. IUSA Governance

a. IUSA Board Structure and Membership

The Energy East corporate names changed to Iberdrola USA on November 30, 2009. IUSA's Bylaws, Amended and Restated on January 19, 2011, provide that the "business and affairs of the Company will be managed under the direction of its Board," and that the Board may "delegate all or some of its authorities delegable by Law or the Bylaws to the officers, agents and employees of the Company." IUSA's board must have between three and eleven directors. At least one member must qualify as "independent," a term the by-laws define as not having a material relationship with the Company.

The IUSA board of directors currently has 10 members. Two would qualify as independent directors under standard U.S. definitions. Liberty asked about business connections between the independent IUSA director engaged in substantial businesses (largely in the renewables field) and ISA. Neither ISA, IUSA, nor the director is aware of any value-creating relationship with any ISA entity since at least 2008. Another director deemed independent by IUSA left ISA subsidiary Scottish Power in June 2010 (having most recently served as Managing Director for Energy Networks, a position similar to that of the IUSA CEO). The remaining seven IUSA directors serve currently as officers of ISA and as directors of the other principal subsidiaries termed by ISA as "subholding companies." The next table provides information about the current IUSA directors.

Name/Function	***Tenure***	***Background***
Chairman: Chief, ISA Networks Group (Spain)	Jan. 2011	• Chair of subsidiary Scottish Power board • Former ISA GM positions in distribution/networks • Executive Director of engineering and construction sub. • Chmn./Exec. Dir., Spanish electricity distribution sub.
Legal Service Director, ISA's Americas' businesses (Boston)	Apr. 2011	• IUSA Legal Service since 10/10 • VP, ISA Corporate Services since 2/11 • Board member, ISA Mexican subsidiary since 3/11 • Spanish government lawyer, 2/02 to 9/10
ISA Networks Financial & Control Manager (Spain)	Apr. 2011	• Board/audit comm. member Spanish elec. distribution sub. • Board member of subsidiary Scottish Power • Started with ISA in 1978; for nuclear plant construction • ISA Director of Admin. & Mgmt Control (1985-1995) • ISA Staff Administration and Social Prevision Director (HR)
ISA Human Resources Director (Spain)	Dec. 2009	• Started at ISA in 1998, Transformer Project Management • Served in General Services admin. and exec. development • Former HR Director, IIC and Renovables • HR Mgr in 2009 (corp. functions and comp) for several subs
CEO, ISA Spanish Distribution Sub. (Spain)	Apr. 2011	• Began with Iberdrola in 1987 • Director of Scottish Power
Director, ISA International Businesses (Spain)	Feb. 2009	• 20 years at IBM • Former board member of IUSA gas utility subsidiaries • Head of ISA International since January 2009; resigned 2012
Former Scottish Power Executive (Scotland)	Jul. 2010	• Former head of Energy Networks of sub. Scottish Power • Non-Executive Director of Scottish Water

Independent Director (U.S.)	Jun. 2009	• Operating Partner of Element Partners, LLC • Sr. VP/Mgng. Dir., Strategic Growth, of Weston Solutions • Director of NRG Energy and World Resources Institute • Adv. Board of ACORE; former St. Joseph's Univ. trustee • Former PA Secretary of Environmental Protection • Former partner in Peregrine Technology Partners, LLC
IUSA CEO (U.S.; Not Independent)	April 2011	• CEO IUSA; officer/director of other IUSA subs • Various positions with Energy East, primarily financial
Independent Director (U.S.)	June 2009	• Former chief of staff for City of Rochester • Trustee, board member for Rochester area schools, businesses • Board member Iberdrola Foundation

[redacted]

b. IUSA Board Chairs

The board elects a Chairman from among its members. The Chief of ISA's Networks Group serves as the IUSA board chair, assuming that position in April 2011, approximately three months after his first appointment as an IUSA director. Two persons reporting to him in his ISA Networks position and a recently retired networks executive of ISA also serve on the board. Two IUSA chairs preceded him. The Energy East CEO at the time of ISA's acquisition served as chairman through and after the acquisition, departing in October 2009. A senior ISA executive succeeded him. The head of ISA's International Businesses (still a member of the IUSA board) filled the role on an interim basis, also serving in effect as the most senior executive for U.S. operations. She became an IUSA board member in 2009. She described her role as senior IUSA executive and board chair as interim, pending a determination of whether the IUSA board required a chair on a long-term basis.

The election of Chief of ISA's Networks Group as chair of the IUSA board in April 2011 reflected the recent reorganization that created the Networks organization, which he heads as a senior ISA executive in Spain.

The current CEO of IUSA also became am IUSA board member in April 2011. He reported that his election came after his recommendation to the ISA CEO that the IUSA CEO should be an IUSA board member.

c. IUSA Audit and Compliance Committee

i. Structure and Responsibilities

The IUSA bylaws allow the board to create and maintain committees by resolution, including an Executive Committee, but require only the Audit and Compliance Committee (A&CC) to exist permanently. The A&CC is in fact the only committee that the IUSA board has ever established and operated. The IUSA A&CC consists of three directors appointed by the board for indefinite terms. One member must be independent in the judgment of the board and as required by IUSA's bylaws. All members must have financial experience (emphasizing accounting, auditing, and risk management), and must understand basic financial statements. The Director of Internal Audit at IUSA reports functionally to the chair of the IUSA A&CC.

The IUSA A&CC members are:

- ISA Networks Business Control Manager (Spain)
    - Director of IUSA and Chair of IUSA A&CC since April 2011
    - Bachelor of Economics and Business Administration
    - Entire career at Iberdrola, including nuclear construction support, accounting and finance, human resources, financial and control director for ISA Network business
    - Member of Iberdrola Distribución Eléctrica board and Auditing and Performance Committee, and member of Scottish Power Energy Networks Holding board of directors
- U.S. Independent Director
    - The declared independent director member, an IUSA director and A&CC member since 2009
    - Operating Partner of Element Partners LLC (an investment firm specializing in energy and clean technology investments); Senior Vice President and Managing Director, Strategic Growth of Weston Solutions, Inc. (a restoration, property redevelopment, design/build construction, green buildings, and clean-energy environmental services company)
    - Director of NRG Energy, Inc. (a wholesale power generator operating about 26,000MW of capacity and a retail supplier through Reliant Energy and Green Mountain Energy Company to more than 1.8 million customers) and of World Resources Institute (a global non-profit environmental organization dedicated to addressing environmental challenges and sustainable development); member of Advisory Board of ACORE (a non-profit organization that promotes renewable energy options for electricity, hydrogen, fuels and end-use energy)
    - Formerly a partner of Peregrine Technology Partners, LLC (commercialization of clean technologies) and a Trustee of Saint Joseph's University
- Legal Services Director, IUSA's U.S. and other Americas' businesses (Boston)
    - IUSA director and A&CC member since 2011
    - ISA's Legal Service Director for U.S. businesses since October 2010 and ISA Vice President of Corporate Services since February 2011
    - Member of Iberdrola Mexico board of directors since March 2011
    - Government Lawyer (on leave).

The A&CC Committee operates under a charter, last amended on April 14, 2011. This charter requires the members to possess the following skills, the existence of which Liberty's interviews with the IUSA directors confirmed:

- Accounting, auditing or risk management experience sufficient to discharge responsibilities as members of the committee
- Ability to read and understand IUSA's basic financial statements.

The IUSA A&CC must meet at least four times per year. The charter declares the committee's purposes as encompassing assistance to the IUSA board in overseeing:

- Integrity of financial statements and internal controls
- Compliance with legal and regulatory requirements
- Independence and qualifications of the independent auditor
- Performance of Internal Audit and of the independent auditor.

Committee Charter Article 4 enumerates A&CC Committee functions:

- Oversight of Internal Audit
  - Oversee independence and efficiency
  - Assure sufficient resources and qualifications to carry out its functions, including ISA's "Basic Internal Audit Regulations"
  - Approve Internal Audit's guidelines and annual action plans, in accord with ISA Internal Audit guidelines and general plans
  - Propose for board approval Internal Audit's annual budget
  - Propose for board approval the appointment or removal of the Director of Internal Audit
  - Oversee Internal Audit
  - Receive (concurrently with the ISA Director of Internal Audit) annual activity reports from Internal Audit, with such reports to include all incidents, accounting irregularities, and illegal acts discovered
  - Receive regular reports on Internal Audit activities (with parallel reporting to the ISA Director of Internal Audit to assure conformity with guidelines and general plans established at the ISA level)
  - Ensure that IUSA managers comply with Internal Audit report conclusions and recommendations
- Internal Monitoring and Risk Management Systems
  - Understand and review the financial information process and internal monitoring systems linked to company risks
  - Ensure the identification, management, reporting, and mitigation of IUSA and subsidiary main risks, guided by processes and general systems established at the ISA level
  - Review with independent auditor, Internal Audit and management internal-controls system adequacy, effectiveness, significant deficiencies, changes
  - Accounting practices, and disclosure controls and procedures
  - Review current accounting trends and developments, and respond appropriately
  - Maintain relationships with the ISA-level Risk Division and Audit and Risk Supervision
- Accounts Auditing
  - Propose to the board conditions for contracting with the independent auditor under the applicable parent policy
  - Ensure independent auditor independence
  - Receive from the independent auditor regular reports on issues, legislative developments, auditing practices, in communication with ISA Internal Audit
  - Review the contents of audit reports before issuance
  - Oversee management's replies to audit reports
  - Keep the board abreast of regular reports to the committee from the independent auditor about audit plans, and results
- Preparation of Financial Information
  - Oversee preparation and integrity of financial information of the Company, assuring statement preparation in accordance with standards used for annual financial statements
  - Advise on changes to ISA-level accounting practices and policies

  - Review management certifications in financial reports regarding compliance
  - Oversee compliance with the legal requirements and the correct application of principles and practices applicable to the annual accounts
- Legal and Governance Compliance
  - Oversee compliance with laws, internal regulations and bylaw provisions
  - Oversee operation of Compliance Program, meeting, at least twice per year with the Chief Compliance Officer (CCO) and the Director of Compliance to review compliance programs to prevent and detect violations, to review reports of significant compliance and ethics related activities within the Company, and to review certifications by CCO and Director of Compliance of Compliance Program compliance and effectiveness
  - Review the status of compliance with laws, regulations and internal procedures and of systems designed to promote compliance
  - Maintain a relationship with the ISA-level Corporate Social Responsibility Committee
- Potential Misconduct
  - Establish and supervise employee channels to communicate confidentially about irregularities
  - Undertake necessary investigations of third-party claims irregular conduct
  - Inform the IUSA board and the ISA board Auditing and Risk Supervision Committee chair.

IUSA's A&CC Committee must meet at least four times per year. It has met the minimum number of required times, plus one telephonic meeting in 2010. All the other meetings have taken place in New York City, except for two 2009 meetings in Madrid.

In performing its duties, the IUSA A&CC has access to the information, documents, and records it deems necessary and it may retain outside advice, in accord with IUSA bylaws.

d. Governance of IUSA Subsidiaries

Operating as a wholly-owned subsidiary of IUSA, RGS Energy Group (RGSEG) wholly owns NYSEG and RG&E, which continue to exist as distinct corporate entities. All of the directors of these entities are employees; none are outsiders. The current officers and directors RGSEG are:

- Directors: Paul Connolly, Robert Kump
- Officers: Kump - President, CEO, & Controller; Connolly - Secretary; Michael McClain - VP & Treasurer

NYSEG and RG&E both employed the same sets of directors and officers at the time of this report (subsequently making changes, including replacing the Spanish directors with IUSA personnel):

Directors

Senior ISA Attorney (Spain)	IUSA CEO	IUSA NY Pres.
ISA Int'l Business Head (Spain)	ISA Admin & Control Head	IUSA COO

Officers

IUSA General Counsel	IUSA Senior Attorney

IUSA VP Gas Assets	IUSA, VP, Controller, Treasurer
IUSA VP Energy Supply	

e. IUSA Board Meetings and Trips to/from Spain

The first IUSA board meeting took place in September 2008. There were four meetings in 2008, nine in 2009, eight in 2010, and four in 2011. The majority of meetings have occurred in New York City. The next table shows earlier IUSA board and committee meetings.

IUSA Board Meetings			
2009		***2010***	
Jan. 13; NYC	Oct. 8; Portland	Jan. 8; Phone	Jul. 8; NYC
February 12; NYC	Oct. 20; Boston	Feb. 18; NYC	Sept. 29; Albany
Jun. 5; Portland	Oct. 22; Phone	Apr. 14; NYC	Nov. 16; Phone
July 8; Portland	Dec. 10; NYC	May 25; Phone	Dec. 9; Boston
Aug. 24; Rochester			
IUSA A&C Committee Meetings			
2009		***2010***	
Jun. 2; NYC	Oct. 15; Madrid	Feb. 17; NYC	Oct. 14; Phone
Jul.16; Madrid	Dec. 10; NYC	Apr. 14; NYC	Dec. 9; Boston
		Jul. 8; NYC	

We asked for the number of trips made by "each executive and director based in Spain" since the beginning of 2009. The IUSA response provided information only for IUSA directors and, included the ISA chair and CEO, even though he is not an IUSA director. The next chart summarizes the response.

IUSA Director NY/NE Trips (2009-Present)

Position	IUSA Position	Trips	Purpose		
			Board	Mgmt.	Other
ISA Chair & CEO	ISA Chair & CEO	10	0	7	5
ISA Networks Business Control Manager	IUSA Board & A&CC	0	0	0	0
Director Iberdrola USA, Inc.	IUSA Board	0	0	0	0
Formerly Director Iberdrola USA and Iberdrola USA Audit and Compliance Committee	IUSA Board & A&CC	0	0	0	0
Human Resources Director, Iberdrola Group	IUSA Board	6	5	3	0
Chief, ISA Networks Group	IUSA Board Chair	2	1	1	0
Formerly Director Iberdrola USA, Iberdrola USA Audit and Compliance Committee, NYSEG	IUSA Board & A&CC	12	8	4	0
Formerly Director Iberdrola USA	IUSA Board	9	0	0	9
Head of ISA's International Businesses	IUSA Board	21	11	17	13
Formerly Director Iberdrola USA, NYSEG, and RG&E	IUSA Board	18	3	9	11
Formerly Director Iberdrola USA, Iberdrola USA Audit and Compliance Committee NYSEG	IUSA Board & A&CC	5	4	0	1
Former Scottish Power Executive	IUSA Board	3	3	0	3

Note: Some IUSA directors not in position listed as far back as the start of 2009

f. Regular Information from IUSA to the ISA Board

The board of directors and "certain management in Spain" receive some information regularly: Performance Management Reports, IUSA-weekly updates, Monthly Highlight reports, Business

Transformation updates and Earnings Monthly reports. Interviews demonstrated that the parent board members do not routinely examine information about U.S. operations at a significant level of detail.

g. IUSA Board Compensation

The three IUSA independent directors receive [redacted] per quarter, regardless of attendance. The independent member of the A&CC Committee receives an additional [redacted] per quarter. The three directors deemed independent can secure expense reimbursement in accord with IUSA's travel policy, which provides for transportation, meals, lodging and related expenses. The ISA executives serving on the board do not receive separate reimbursement, but may receive expense reimbursement in accord with the travel policy of the Iberdrola entity employing them.

No form of payment other than the above-listed director payments, is made to any current IUSA board member.

3. Board Performance Assessments

The Boards of IUSA, NYSEG, and RG&E do not undertake structured assessments of their performance as individuals or as a group. There are no similar assessments of the effectiveness of the relationship with senior U.S. management, or of the quality and of information presented by management.

IUSA does not perform outside assessments of board structure or performance. ISA has been doing so annually. A major international firm performed such an assessment in late 2010. It addressed the board, its committees, and the CoB/CEO. The firm conducted interviews with board chairs and secretaries, and benchmarked performance against best practices. The evaluation included:

- Composition
- Operation
- Skills development and performance of duties
- Relationship with other entities
- Improvement opportunities identified in previous evaluations.

The outside firm found the board to perform well against the comprehensive standards established and the benchmarked companies. The more significant improvement opportunities found were:

- Board
  - Comparatively large number of directors with long tenures
  - Comparatively low number of directors with experience in ISA business sectors
  - Lack of annual assessments of individual director performance
  - Meeting of independent directors without the presence of management directors
  - More meetings of the board outside Spain
- Nominating and Compensation Committee
  - Charting desirable board skills mix
  - Lack of structured use of outside advisors to assist with director nominations
  - Lack of training and regular updates for members about compensation policy

  - CEO succession planning
- Chairman of the Board and CEO
  - Lack of separation of CoB and CEO positions
- Executive Committee: none
- Audit and Risk Supervision Committee: none
- Corporate Social Responsibility Committee: none

4. Limitations on Access to Board Members and Documentation

ISA refused, initially and after time-consuming and laborious effort and extended discussion, to provide a very large portion of the parent board member documentation that Liberty requested. That request, standard to our reviews of governance, requested information such as minutes, pre-meeting distributions, in-meeting presentations, and post-meeting follow-up. ISA agreed to provide only information making specific reference to U.S. activities, operations, and issues. While later resolved partially, ISA also initially declined to make ISA board members available for interviews, and exhibited resistance to Liberty's interviewing some senior ISA executives. ISA cited many reasons over a long period for seeking to foreclose or restrict access to information about the parent board and members, including:

- The ISA board has little to do directly with U.S. operations, expressed in such terms as:
  - "[D]oes not enter at all in the operations of the New York Companies"
  - "[D]oesn't have any role in the effective management of the NY companies"
- ISA "is based in Spain and subject to Spanish laws"
- "[I]ndiscriminant open access to the minutes…would not match well the Spanish legal system of the confidentiality of the Board meetings demanded by ISA shareholders and by the Spanish Stock regulator"
- Scheduling interviews with all ISA board members and Spanish executives would be "inefficient and burdensome" and "repetitive and irrelevant"
- New York is too small a part of ISA to justify the interviews requested
- The directors are too highly respected and busy to justify interviewing them in the numbers requested
- The director interviews would cause their "involvement in activities that are clearly outside the scope of their duties"
- The Code of Conduct agreed to as part of ISA's acquisition of Energy East requires only the submission of minutes that "discuss NYSEG, RG&E or the relationship among NYSEG or RG&E and its affiliates"
- That the parent board was not informed in any substantial way about the "details" of U.S. operations
- The board operates as a unitary body, rather than as individuals
- Spanish law and business custom were contrary to the requests
- The intent of the requests appeared in the nature of a "criminal proceeding" or "cross examination"
- The requests were "confrontational"
- ISA had no ability to "compel" participation by its directors, because they are not company executives.

ISA's position finds no support or precedent in any of Liberty's many previous engagements involving governance reviews in support of the missions of U.S. utility regulatory authorities. Our requests here were no broader (and in fact scaled back) than what we have routinely sought and received in other reviews. The most recent example is our audit of Consolidated Edison, whose board was fully cooperative with significantly more extensive requests and burdens on them. Moreover, while we certainly appreciated that cooperation, it was no more than we have customarily received in our relevant work for many U.S. utility regulatory authorities.

In short, the tenor and breadth of ISA's strong opposition to both documentary and interview requests was simply unprecedented for us. It also served as a major barrier in performing this audit, requiring extended delays and expenditures of very large amounts of ultimately unproductive time.

We examined ISA's position that the merger proceedings support the refusal to provide commonly requested and supplied board information and access. The September 9, 2008 Abbreviated Merger Order in the docket (07-M-0906), addressing the Iberdrola acquisition of NYSEG and RG&E required parties to seek to resolve "any remaining Code of Conduct issues" raised in the proceeding. Participants in those efforts produced agreement on a proposed Code of Conduct. They filed this proposed Code with the Commission on December 8, 2008. This same filing also cited agreement to an addition to the "Transparency and Reporting Conditions" of the Abbreviated Order under which Staff would have access in New York to English versions of minutes and related documents of the parent board and committees, "to the extent that such minutes, including presentations or other documents discuss NYSEG, RG&E or the relationship among NYSEG or RG&E and its affiliates."

The terms of the agreement recite specifically that it:

- Completely resolves "the Code of Conduct issues that were raised in Case No. 07-M-0906"
- [C]ontains the entire agreement of the Signatory Parties" regarding those matters
- Applies "solely to and are binding on each Signatory Party only in the context of this proceeding"
- Forbids reliance by anybody on the positions in the agreement "except in furtherance of the purposes and results" of the proposal set forth in the filing.

Whether this agreement applies to or overrides broader Commission authority involving the conduct of management audits under State statute requires a legal judgment, which is outside the scope of this audit. We address our ensuing conclusions, regardless of what judgment in that regard might ensue, to the question of how the refusal to provide requested information and the accompanying delay and unproductive hours expenditure relate to:

- The ability to address the scope of this audit
- The much broader and more fundamental question of establishing a transparent regulatory relationship
- Concerns about the degree to which foreign ownership of regulated entities performing important public service responsibilities may impose unique challenges

- How performance compares with a particularly wide range of experience with top leadership of U.S. utilities and utility holding companies, including some of the country's largest.

I. Governance - Conclusions

11. ISA operates under a structured and comparatively well documented set of governance policies and guidance, procedures, and controls.

We understand that U.S. requirements do not drive these matters. However, we did observe that the structure, documentation, and transparency of ISA's system, structure, and methods of governance are commensurate with what we have seen at other major, publicly traded U.S. utility and utility holding companies. There has been somewhat less formality with respect to IUSA, but ISA has assigned a governance-dedicated employee to U.S. operations, and has been moving to increase the formality and structure applicable to IUSA governing authorities. ISA monitors governance trends in the international business community, and regularly tests itself against them.

12. The parent board consists of distinguished and very capable individuals.

They come predominantly from banking, legal, educational, and governmental backgrounds, having served long years in high positions. They are impressive in their backgrounds, their contributions to European (predominantly Spanish) economy and society, and in their bearing and sincerity.

13. The structure and scope of parent board organization and activities differ significantly from what is generally accepted in the case of U.S.-based utility companies. *(Recommendation #5)*

The ISA parent's board differs in substantial ways from what we have learned through our experience with U.S. holding companies. It does, as noted, operate under a well-documented and formalized set of guidelines and procedures, it seeks to identify, consider, and react to international governance trends, and it benchmarks a range of tangible characteristics. However, it differs in a number of important ways. As to membership, it differs with respect to tenures, ages to some degree, the presence of proprietary directors, and different emphases with respect to professional- and business-background diversity. With respect to structure, it operates with comparatively fewer committees, makes much greater use of an executive committee, and has no finance, planning or operations-focused committees. The executive committee (apart from the CEO and lead director) consists of two of the longest tenured directors (34 and 19 years) and the two proprietary directors. The lead director (recognizing that the position is a newer one for ISA than for many U.S. utility holding companies) undertakes a somewhat narrower range of activities. The role also differs from what we have seen at other U.S. utility parents; specifically, there is very little oversight of operations "details."

We emphasize that we do not seek to judge the ISA board against the standards against which it judges itself. Our purpose here is to compare it with what we have seen in the U.S. This distinction has two important ramifications. First, as the following conclusions address, there is very little oversight or detailed knowledge about U.S. operations at the parent board level.

Second, the differences are so embedded and so much resulting from differing organizing concepts than those with which we are accustomed in the U.S., that it is difficult to see a practicable way to structure changes that would be meaningful, while, at the same time within the range of alternatives that ISA would likely consider feasible or appropriate, judging, as it may be expected to judge, from the perspective of a global company whose U.S. utility operations are comparatively small (even though such operations are not inconsiderable when compared with other regional U.S. utilities).

Even where marginal changes would otherwise be recommended, one need consider that a board's overriding mission is to represent and protect shareowner interests. Even those governance changes (by government authorities or exchanges) that U.S. business has seen in recent years focus primarily on those interests. It is therefore not realistic to expect changes that a major, respected corporation deems inimical to that board role. That said, we approach our governance work from the perspective that boards overseeing operations affected so substantially with the public interest and conducting business under grants of public authority do not serve shareowner interests well in the long term if they operate under governance structures that fail to focus on the diligent exercise of such operations. The bottom line should be to operate under the premise that shareowner and public interests converge in the long run, which should give corporate leaders a strong interest in incorporating the views of regulators into their governance process. Recognizing this convergence should come readily to enlightened corporate leaders. What generally becomes much more difficult is determining the degree to which "hard" versus "soft" or direct versus indirect measures best serve the process of reaching a governance structure that a company is comfortable will serve shareowner interests as the company's leadership sees them, and that those charged with regulating to ensure the public interest consider important.

We have not seen divergences of the magnitude at issue here. We have ordinarily dealt with much more marginal differences or we have been engaged in a review of companies under a level of financial or regulatory stress so great as to make them amenable to more fundamental change than we think exists here. The next conclusions will focus more clearly on the differences, which we ask the reader to examine in light of the fact that ISA operates with an extraordinary level of confidence in not only the soundness of all aspects of its governance, but in the firm belief that it is a world leader in the field. What will become clearer in the recommendations section is that this confidence and belief make it very difficult to craft recommendations that combine the ability to address effectively issues of depth of oversight and knowledge of U.S. operations with enough "traction" to spur the company to voluntary change. In the absence of volition, questions regarding the effectiveness of compulsion inevitably arise. We see little likelihood of volition and we must defer to others the matter of exercising the latter in an area that goes to the heart of board purpose, function, and stakeholder definition.

14. ISA does not strongly emphasize board member diversity of business and operating skills and experience, which contrasts the Company with what we have observed at major U.S. utility enterprises. *(Recommendation #5)*

We found, as did the outside consultant who reviewed the parent board found, that the members as a group do not bring strong outside (*i.e.*, outside their membership on the boards of ISA and its predecessors) experience as an overall group in operations like those of ISA. Providing a robust mix of operations experience has not operated as a significant factor in their selection. Two members represent Spanish banking enterprises who have the power to secure board membership through the size of their stock holdings. As the consultant also found, comparatively long tenures and high age distinguish the ISA board.

Despite their exceptional personal qualifications, the ISA board does not display the robust range of experience that we have observed to be an important criterion in the case of U.S. utility holding companies. A comparison with the parent boards (forgetting for the moment the question of geographic diversity) of other New York utilities highlights this distinction (again giving great respect to the distinguished backgrounds of individual ISA directors). In some respects, this difference corresponds to what we view as a more significant distinction; *i.e.*, in the roles that the ISA parent board fulfill, as compared with their counterparts at U.S. utility holding companies. The ISA board's role has been described (and confirmed by board member interviews) as extending to the establishment only of general strategy, without involvement in the details of operations by the subholding companies, which include IUSA.

15. The parent board does not provide a substantial level of independent oversight over New York utility operations. *(Recommendation #5)*

Liberty confirmed through a review of [redacted].

Interviews with directors confirmed the lack of involvement in details. There was one consistent exception to the lack of detailed information about operational details. Throughout 2010 and well into 2011, staffing reductions formed a [redacted]. In October of 2010, the ISA CEO [redacted]

> [redacted]

As 2010 progressed, [redacted]

We sought to determine how: (a) parent board attention to U.S. matters compared to that provided to other utility operations (Spain, Scotland, Brazil), and (b) how the so-called "general strategies" that the board agreed it oversees relate to U.S. operations. ISA's refusal to provide access to board materials prevented us from doing so. We therefore could not determine how this level of attention to U.S. utility operations (or other U.S., non-utility operations for that matter) compared with the parent board's role vis-à-vis other operations. Despite repeated and arduous attempts to secure access to the range of parent board materials that we routinely examine (and which holding companies routinely provide), we were refused access to any materials other than those directly referencing IUSA. As discussed later, this conspicuous refusal denied us access to information addressing two other important issues: (a) the degree to which the general strategy either supports or contravenes U.S. utility interests, and (b) the degree to which plans for other U.S. operations may conflict with the interests of U.S. utility operations. This second issue particularly concerns II&C. It is clearly a significant priority for ISA to make II&C a force in the U.S. market for design and construction management, in the utility and other areas. II&C has encountered sufficient resistance in entering the U.S. market, having gained little success outside of work for the Maine utility and Renovables, both affiliates. We observe that ISA intends major, new levels of service to IUSA as a means for helping to dissolve this resistance, and to establish a foothold for II&C.

Without the ability to determine whether U.S. utility operations receive less attention by the parent board, we nevertheless can conclude that they receive a level of attention that is by far less substantial than we would observe in the case of any U.S. holding company, including those that have some operations that form a comparatively small part of total operations. We do observe, however, that ISA is an unusually large holding company by comparison even with some of its larger U.S. counterparts. The question to us, therefore, is not whether IUSA receives substantial attention from the parent board; it admittedly does not. The questions then become whether such independent oversight is needed at all, and if so, where it occurs. It does not take place at the IUSA board, which is dominated by ISA, Spain-based executives. Moreover, even that executive team contains a number of persons who report to the same senior Spanish executive. It has only two independent members. ISA claims a third, but we do not believe that a recently retired executive who served in a similar role in Scotland to that served by the IUSA senior executive to be independent. Nor does he act in all respects as a director would, engaging in direct one-to-one discussions with the IUSA CEO on a frequent basis about operational issues, and serving on an otherwise management-only business development group. The two truly independent directors both present strong credentials and expressed perspectives on their roles that we found comforting in terms of knowledge and interest in U.S. operations matters. However, including them in a group dominated in numbers by senior Spain-based ISA executives does not create a structure that can be considered as promoting anything near the level of independence that is now a hallmark of U.S. industry generally, and the utility industry more specifically.

Interestingly, ISA has operated in Scotland and in multiple regions of Spain advisory boards designed to provide at least observations and insights that are independent of management. Senior executive ISA leadership has described their input as valuable because ISA "is not there" in the sense of on-the-ground, senior leadership. None has existed and none is proposed for the U.S., which is far more remote from such leadership. Consequently, one must conclude that no directly empowered governing authority or advisory group has responsibility for or exercised independent oversight over IUSA. Moreover, the connections of the Spain-based IUSA board members must be viewed as not very substantial. The prior and current members spend little time in the U.S., and even those meetings that have occurred have rarely been in the service territory; New York City has served as the predominant location.

16. The IUSA and the IUSA subsidiary boards provide a more detailed level of oversight, but they are dominated by Spanish executives, which continues to leave an

"independence" gap by comparison with U.S. utility holding companies. *(Recommendation #5)*

The U.S. board is dominated by Spanish senior executives. They are not independent. In fact, some actually work in direct lines of authority with respect to each other. Only two directors qualify as independent by standards used in this country. We found both of them to be strong and capable members. IUSA claims a third as an independent director, but he is a recently retired senior executive from Scotland. The two independent directors are both capable, but their presence does not materially change the conclusion that the IUSA board is a management dominated one. NYSEG and RG&E both have their own boards, but they consist entirely of a small number of executives.

Domination by company executives is not, in itself, necessarily significant; many utility holding company boards have subsidiary boards composed entirely or nearly entirely of management personnel. What makes this characteristic material here is the fact that the independent board at the parent level does not exercise substantial oversight of U.S. utility operations.

U.S. board membership also has not been stable. There were major changes in 2011. Of the eight non-independent directors (seven of whom are senior Spanish executives), only one has been on the board since early 2009, and five were appointed this year. Collectively, the non-independent directors have spent little time in the U.S., with most of that time coming at board meetings. Through April 2011, the IUSA board has met only once per year in the service territory. The average number of U.S. visits by IUSA's Spanish directors (excluding the ISA CEO and the ISA executive for international businesses, whose U.S. concerns include the large U.S. wind business of affiliate Renovables) across the period from 2009 through 2010 average far less even than the number of IUSA board meetings. Moreover, during that period the only two meetings in the New York serving area were at Rochester and Albany. During this period there were, by comparison, multiple meetings in New York City, Boston, and by phone.

The IUSA board does engage in a greater level of detail about U.S. operations, but its oversight has not been at the depth one would expect of a utility parent board in the U.S. Moreover, a series of ISA groups seeking global best practices, already gives senior executives at the ISA and subholding company levels ample opportunity for looking at operations practices. There are also three persons from Spain assigned to the IUSA executive organization (CFO, co-COO, and a VP in engineering). The retired Scottish Power executive who serves on the IUSA board also reports reasonably frequent one-on-one exchanges with the IUSA CEO and COO on operations matters, and he serves on a development committee otherwise comprised of IUSA executives. With all of these "lines of communications" between IUSA and Spanish executives at the board, executive, and executive and management committee levels, it is difficult to discern where board oversight and management direction and supervision begin and end with respect to each other.

With respect to the depth of board engagement, for example, the IUSA board did not even adopt budgets in one period until more than half the year had passed. Our interviews disclosed a lack of board member involvement in U.S. CEO compensation. Another example came in the form of statements by a board member in his area of management responsibility that were in direct conflict with the actual operation of IUSA operations. We would have expected significantly more concern at the IUSA board about staffing changes and difficulties in making required capital spends. Perhaps most telling was the fact that the U.S. CEO was not added to the IUSA board until April of 2011.

We also found it curious that ISA has decided to use advisory groups consisting of outsiders in at least two regions in Spain (and Scotland as well). The rationale that top Spanish executive management assigned to the creation of the Spanish bodies (that ISA "is not there") would seem to apply with much greater force a continent and an ocean away in the U.S. There has been no such group in the U.S. The utility entities in Spain and in the U.K. have their own boards; therefore, the advisory bodies do not seek to fill a governance role. Similar use of an advisory committee in the U.S. would thus not address the questions of independence or depth of oversight. What is more telling about the absence of such a group is why senior ISA leadership has found such groups useful much "closer to home" than is true of U.S. utility operations.

17. Senior Spanish executives and the parent board do not take a direct interest in or have more than very general knowledge of the details of U.S. regulatory requirements. *(Recommendation #6)*

Interviews with senior Spanish executives and board members confirmed that knowledge of U.S. regulatory requirements at a meaningful level of detail is left to U.S. management. There exists a general understanding, particularly insofar as revenue is affected. Very little information about U.S. regulatory matters appears in the board materials provided. Even some of that used phrasing, terminology, and titles that demonstrated a lack of familiarity with basic New York regulatory elements.

We also found surprising the lack of mention of IUSA's New York President and Vice President-Regulatory Strategy as important links in keeping Spain aware of U.S. regulatory requirements, developments, actions, trends, and concerns. A senior Spanish executive was the most commonly identified source of U.S. regulatory expertise for leadership in Spain. She still serves on the IUSA board, and was until recently the chief Spanish executive responsible for IUSA operations since the start of ISA's ownership. She described herself as the U.S. regulatory "conscience" in Spain. She had more than a general familiarity with U.S. regulatory matters, but not at what appeared to be a very deep level. Moreover, as the Spanish executive responsible for manifesting the senior executive "presence" for operations outside Spain, she has been to the U.S. more than the other Spanish executives. However, as she herself noted, the completion of a multi-year rate agreement in New York, coupled with fundamental questions about the course of utility regulation in the U.K., has significantly reduced her presence in the U.S.

18. Routine information sources available to European directors (and any senior managers with significant actual or potential influence over New York operations) should be at a scope, level of detail, and frequency to provide them with sufficient information to carry out their responsibilities as they affect those New York operations. *(Recommendation #5)*

The information available comports with the level of oversight that ISA parent board members and executives purport to provide with respect to IUSA. Thus, while the parent board does get information consistent with its level of oversight, that information is far less than what one typically would expect to find in cases of the independent board operating at the holding company level in the U.S. The IUSA board does get more information; in fact it compares favorably with what was provided to the Energy East when it operated (as the IUSA board does not) as an independent governing authority. Nevertheless, the IUSA board information remains at a level that is not fully commensurate with what one would expect at an independent board. Its use of only a single committee (Audit & Compliance) further influences the depth of oversight that the IUSA board brings, when compared with other U.S. utility holding company or parent boards.

The CEO of the parent acknowledges a similar level of involvement in U.S. operations to that of his board; *i.e.*, general direction and oversight. We found senior ISA executives at times to be unfamiliar with key IUSA executives. We observed a number of other telling aspects, not only regarding the level of engagement on U.S. matters, but even the level of agreement about them:

- The example cited earlier of a senior executive from Spain describing a practice in direct opposition to how we found it described and how IUSA HR management understood it.
- As we will discuss later, a failure [redacted] to adopt planned incentive compensation measures for 2011 caused IUSA employees to work for much of the year without knowledge of how their compensation would be affected by measures intended to later be subjected to quantifiable metrics.
- A responsible Spanish executive did not understand these tardily established matters to be a required element of U.S. compensation.
- Another senior Spanish executive was unable to articulate meaningful examples of values and metrics ISA applies globally (including at IUSA), even though he asserted a direct role regarding them.
- A conflict in description of roles affecting IUSA as between two very senior and responsible Spanish executives, later rationalized by the assertion that the more junior executive was "joking" when describing resource limitations affecting his performance of the role in question.

19. Outside consultants have reviewed board performance relative to peers, but there had been no self-assessments at the time of our audit work. *(Recommendation #7)*

Neither the ISA nor the IUSA boards had adopted the now standard U.S. practice of conducting self-assessments of board and committee performance by board members. There were similarly no structured board assessments of senior executive management performance.

20. Management takes what, from our experience with many other utilities, is an unusual perspective on regulatory transparency. *(Recommendation #6)*

Liberty made requests regarding the ISA board that differ in no respect from what we have routinely sought and received in numerous other engagements involving U.S. utilities and holding companies. Our prior work includes some of this country's largest such enterprises, and some engagements have involved work in a state representing a small portion of total operations. We believe that a high degree of openness in discussing strategic, organizational, and structural matters is very much the norm in this country. ISA took a very different view in this audit, imposing major barriers, invalid arguments (some very peculiar), and protracted discussions that wasted substantial time and effort.

The approach taken by ISA indicated a belief that "negotiation" of an information exchange "deal" was an appropriate way to respond to the audit requests involved. This approach was taken to an extent not seen in hundreds of projects undertaken by Liberty in over 25 years. We have become accustomed in our work for commissions to a far more straightforward approach, rather than one requiring protracted give and take, small concessions at each step, and vagueness in what is being offered. This approach is ultimately inimical to effective regulation.

We do not opine on the propriety of relying on the settlement agreement in the acquisition case as a basis for refusing our requests. We believe instead that such a narrow, technical basis for non-transparency is far transcended by the issue of what prevailing U.S. practice demonstrates about regulatory relations; *i.e.*, important regulatory procedures (such as a management audit) require open and candid dialogue to be successful. That is true specifically with respect to the direct goals of the procedure itself. It is truer and ultimately more important in creating a climate that produces confidence.

In short, to us it is ultimately not material whether the merger agreement is applicable for all time and in all contexts. What is far more telling is that ISA stands alone in U.S. experience as we know it in its refusal to grant the kind of access we sought. The incongruity of its position is underscored when one recognizes the fairly open and public weight the Commission placed on gaining a full view of how U.S. interests, needs, and concerns are addressed in Spain. The use of arguments about how small U.S. operations are, how busy and important Spanish leadership is, and how Spanish law and business custom differ, can only serve to underscore concerns about "foreign ownership."

We found an unusual degree of emphasis (at both ISA and IUSA) on producing an audit providing a clean bill of health (to paraphrase a senior Spanish executive) and no surprises (to paraphrase a senior IUSA executive). That emphasis was buttressed by another unusual factor observed here. First, we were denied access to plans guiding major organizational and operational changes underway during our audit. These plans resulted at least in major part from an effort to prepare for the audit (we interpret that as producing the desired results of a clean bill of health and no surprises). They were denied us on the grounds that they were prepared at the request of counsel. We find it most unusual for management's change agenda to be under the direction of the legal department. Adding to the emphasis was the allocation of a portion of management and incentive annual compensation to completion of the change agenda.

The correct overriding goal for audits such as this one (and one that we have found confident, well-run companies to share with regulators) is constructive change. Meeting that goal requires candor and openness -- in a word, transparency. Goals like clean bills of health cannot be said to promote transparency; their tendency is instead the opposite.

We observed a related tendency in the "regulatory" attitude demonstrated by IUSA during this audit. There was an evident element of argumentativeness and defensiveness at key junctures of the audit. To some degree we attribute this phenomenon to natural concern about the as yet untested use of audit results in future rate proceedings, given the new approach to management audits in New York. However, we experienced it to a degree (buttressed by transparency concerns arising from our efforts to get information about New York from Spain) that led us to conclude that it remains an ingrained element of IUSA culture.

21. The IUSA board committee responsible for audit matters operates under a typical and appropriate charter and list of functions, is active in defining and exercising committee activities, and has financial expertise, but is concentrated in the ISA executive management members.

Both the parent and the IUSA boards operate under charters appropriate to the typical mission of audit committees. We could not examine how the ISA audit committee generally carried out its charter due to restrictions on information access. The minutes of the IUSA committee and the interviews with its members confirmed that the matters addressed conform sufficiently to the charters. The financial strength of the IUSA board's audit committee lies predominantly in the ISA management members, rather than in its independent members. There exist formal audit committee procedures for treatment of accounting, controls, and audit related complaints, including assurance of anonymity. There is a policy calling for consideration of auditor solicitation and rotation, and the IUSA committee has recently considered changes.

22. The IUSA audit committee has appropriate powers to execute its duties effectively.

The committee has the power to hire/fire, compensate and oversee independent auditors; outside auditors should report directly to audit committee. It also has the power and access to resources to retain its own advisors, but has not done so.

J. Governance – Recommendations

5. The gaps between ISA governance and what one would expect for a company with the breadth of operations of IUSA do not lend themselves to concrete, executable change recommendations. *(Conclusions # 13 through #16 and #18)*

ISA claims to structure and operate governance bodies with reference to international business community standards and trends. The Company clearly pays attention to developments in that environment, applies a set of comprehensive, formal guidelines, policies, and procedures, and makes changes to them, as well as to structure and operations on a basis that can be described as attentive. ISA is also supremely confident that its governance is world class and that how it has fit IUSA into its governance system is appropriate.

It is also true that if one looks at IUSA as a wholly owned subsidiary in a largely utility-based holding company, which of course it is, then its divergence from U.S. experience becomes much less marked. In fact, because ISA has sought to make the IUSA board look more like a U.S. utility holding company board, many of the differences might seem positive.

In the final analysis, however, the IUSA board simply does not compare with a U.S. holding company board. What makes that an important factor to consider is that the parent board does not provide what we have come to expect from a U.S. utility holding company board either. Particularly different is the lack of oversight of utility operations at a substantial level of detail by a board that is independent and that has been structured to reflect the broad and diverse range of experience that U.S. companies now focus great attention on establishing. We hasten to add again that we intend no criticism of the distinguished records and careers of the ISA board members. They are impressive individuals.

Perhaps the comparatively (with reference to ISA's total size) small size of IUSA is a factor. Certainly, ISA manifests some "territorial" distinctions as they concern larger elements of its utility business. There is a Scottish director on the parent board and there have been at least three advisory committees among ISA's Spain and U.K. serving areas.

Perhaps a lower level of attention to territorial issues is natural to expect in the context of such vast and far-reaching enterprises as ISA. Certainly, senior ISA representatives have pointed to the comparatively small nature of U.S. operations and to the prestige of and burdens on their leadership to oppose some of our requests for access to information.

Natural or not, however, IUSA is a large utility in its own right. It has about 6.5 times CHG&E's number of customers. It approaches half the size of ConEd, and is larger than Northeast Utilities, which claims 2 million utility customers and to be New England's largest utility system. Exelon and FirstEnergy, two exceptionally large, dispersed U.S. holding companies serve in the neighborhood of 6 million customers each. Whatever its size within ISA, IUSA comprises in its own right a major U.S. utility. To the extent that governance issues (more particularly regulatory commission interest in them) are relevant at other large utilities, they are therefore relevant at IUSA. When it comes to governance and oversight questions or concerns, we commonly hear from senior U.S. executive management the response of ***"because they own us."***

U.S. utility companies (and other major U.S. major corporations) appreciate the value of oversight at a meaningful level of operational detail by a board that is dominated by outsiders and that has a carefully crafted and diverse range of backgrounds. IUSA does not get that kind of oversight from anywhere. Whether ***"they own us"*** answers the fundamental questions or just moves them around is the fundamental issue. If it does to the satisfaction of regulators, then recommending major change is not appropriate. If it does not, then it remains the case that an exceptionally confident ISA leadership (and moreover prone to asserting factors such as size, Spanish legal requirements, and Spanish business culture as distinguishing features) cannot be expected to be responsive.

Consequently, producing more than cosmetic change (and cosmetic change would not be useful here) will require major contest and controversy, absent a profound shift in attitude. That change will inevitably require addressing the degree to which regulatory concerns should affect company thinking and action about governance, whose overriding focus is shareowner interests. This is true even accepting our views that there is a convergence of the two sets of interests in the long term and that entities operating under public grants of authority to provide essential public services are unique creatures.

We believe therefore that a long-term and evolutionary approach to change in this area is the only feasible way to avoid a tumultuous and extraordinarily controversial path forward. We believe that ISA will, if time there be, have to take a long period to adjust. To do so, however, it will have to show greater interest in and ability to absorb at its most senior, Spanish levels an understanding of the U.S. regulatory regime and expectations. ISA expresses expansion goals in the U.S. It will need to come to understand that expansion in the U.S. may require it to adjust more to business culture here, as opposed to expect U.S. stakeholders to accommodate themselves to Spanish custom and practice as regards critical public service in the U.S. under a public grant of authority.

Across time, the Commission will have many opportunities to observe successes and failures (even the best operating utilities with the most finely tuned regulatory ear experience both, given long enough). ISA will therefore have opportunities to experience: (a) the rewards and penalties that come with them, and (b) whatever connections the Commission makes between those successes and failures and any underlying governance issues of concern to it.

6. **Make IUSA personnel a more central voice in communicating regulatory requirements, expectations, decisions, guidance and other matters to senior Spanish executives and the parent board and establish vehicles to make those audiences more aware of U.S. regulatory issues.** *(Conclusions #17 and 20)*

IUSA senior executive management, with active and regular support from senior U.S. regulatory staff, needs to become the primary voice, or as one senior Spanish executive put it, the U.S. regulatory "conscience" in Spain. From a "trans-oceanic" regulatory communications perspective, several issues appear to us to be pertinent.

First, the head of ISA's international businesses (a lead in this area since ISA's acquisition of Energy East) who has gained essentially a derivative understanding of regulatory detail and nuance, is no longer spending the same level of attention on U.S. issues, and has had her U.S. role in part displaced by the creation of the global networks organization and the establishment of a separate Spanish senior executive to lead it.

Second, there are in some senses "too many" communications links, given the number and rotation of Spanish executives in and out of the IUSA board, the number of Spanish natives filling senior U.S. roles, the many groups examining best practices, and the focus on high-level meetings among very senior representatives (fine in and of itself, but requiring buttressing through dialogue at working levels). Too much can prove to be too little. A result of too many links, as opposed to a highly focused primary channel that is complemented by other links, including some used by ISA and IUSA, can: (a) confuse the difference between a lot of "data" and concise and coherent (*i.e.*, useful) "information," (b) require the audience(s) to rationalize differing viewpoints that inevitably come with many communicators, and (c) produce the worst kind of result; *i.e.*, the transmission of information that is either incorrect or off the real points that need to be understood and on which action is needed.

Third, it does not appear that ISA's senior leadership has placed full confidence in U.S. management. A clearly expressed approach of ISA is that it leaves local issues to local leadership, but it is hard to be fully confident that the reality fully conforms to the "message." The formation of the U.S. executive team is a prime example. The senior executive [redacted] overseeing IUSA operations (prior to the creation of the global networks organization) brought on the U.S. COO and the New York state president before bringing on the CEO (replacing Energy East's departing CEO some time after the acquisition). One would expect the CEO to have the lead role (in fact a dominant one in ordinary circumstances) in selecting key team members, rather than inheriting them all at once on starting the job. The delay in naming the IUSA CEO to the IUSA board until very recently is another signal (either about his stature or about the board itself). The naming of a Spanish executive to serve as "co-COO" with a U.S. counterpart, and the assignment of that Spanish executive to the CEO with no organization under him is out of the ordinary (although we consider him to be a seasoned and very informed individual). Finally in this regard, while there is a regulatory organization in Spain, we understand it to be more a technical group than a policy-oriented one led by persons of the type we generally see as the heads of U.S. utility regulatory affairs organizations.

Fourth is a major disconnect in views about regulatory transparency. We had major problems in getting information about U.S.-affecting matters that take place in Spain. We faced assertions that were so difficult to comprehend and validate as to support a conclusion (ours certainly, and not expressly agreed to by U.S. management) that they did not result from the same thinking we had seen from IUSA personnel.

Fifth is the very question of the role that the parent board and the senior ISA executive team takes with respect to U.S. operations. It allows Spanish leadership to "accept" severe limits on their knowledge and interest. On the other hand, as we observed a reasonably long-term focus on cutting U.S. resources and a lingering inability to pace capital spending at a pace throughout the year that meets regulatory commitments, we question whether full control is truly left at the local (*i.e.*, IUSA in this case) level. Chapter 10 discusses this capital spending issue in the most detail.

We believe that IUSA must develop a structured plan and program for inserting itself into the lead role in assuring that U.S. regulatory requirements, priorities, needs, expectations, and failure consequences become significantly more visible to those in Spain. Equally important in increasing the U.S. voice is the need to get Spain to "listen," and to gain confidence that the U.S. team is the best source of information and insight. Occasional visits by top Spanish leadership, multi-channel links with Spanish personnel inserted in the IUSA organization or on the IUSA board, while helpful, must be considered of secondary importance. We believe that, at least temporarily, the ISA organization in Spain would benefit from inclusion and basing in Spain of a senior person with a long, established, leadership-oriented career in U.S. utility regulation (in a senior utility or regulatory capacity). The development of a strong communications link with the U.S. CEO and the U.S. regulatory lead should exist.

Finally, we believe that a reorientation of the regulatory "attitude" from that we have seen demonstrated at IUSA would be useful. The regulatory team (which we view as including CEO, legal, and regulatory leadership) has made significant strides in improving what all seem to view as a difficult relationship during the Energy East era. What remains necessary is to remove a tendency to react prematurely in defensive and at times argumentative ways. We do not consider regulatory relations to be without risk nor do we preclude the need to exercise care in communications that can have later consequence. What we do believe, however, is that collectively, the team to which we refer here needs to do better at perceiving the "opportunity" that open dialogue and transparency bring. This change does not require fundamental realignment of personnel, if the incumbents work harder to understand that in the long run, minimizing immediate exposure through taking an overly managed and defensive posture is much less effective than engaging regulators more candidly and more with the intent of finding mutually acceptable solutions. To summarize, while IUSA has toned down the "volume" and rhetoric, it has yet to reach a comforting level of success in appreciating and harmonizing viewpoints in a way that consistently demonstrates constructiveness, even where there remain valid differences of opinion with regulators.

7. Institute yearly self-assessments of board performance. *(Conclusion #19)*

Recommendation #5 explains why we are not sanguine about the ability to craft recommendations that will effectively deal with the great "gulf" that exists between highly confident ISA leadership and U.S. experience. Still, we think that adopting the pervasive U.S. practice of regular self-examination will improve both the ISA and the IUSA boards, without undue disturbance to what we view as much more strongly entrenched differences. Structured, comprehensive templates for such evaluations are readily available. The focus on what really makes boards more effective; *i.e.*, they address behaviors, styles, and execution of processes, rather than focusing on the valid, but less central "attribute-based" benchmarking that leading firms do for many major corporations, including ISA, and, we understand, more recently IUSA.

Such assessments force deeper and more honest reflection by boards and directors who take them seriously (which certainly is not all of them). What particularly compels us to recommend them here, apart from conformity to best practice, is that it may help (in the case of the IUSA board) the Spanish executive directors to see what different approaches and attitudes they bring to the board as compared with those of the two independent directors. In addition, IUSA should use the results (with the support of outside, U.S.-based governance experts) to benchmark its directors attitudes, approaches, and concerns with those of boards and directors who do approach U.S. best practices (and not for subsidiary boards, it is critical to note). IUSA should further use such outside support to regularly describe best practices and to offer guidance on gaps.

We emphasize that this tangible recommendation will not of itself accomplish much, particularly in the short run, beyond making leadership more aware of the strengths that can arise from more fundamental change. We would expect costs of less than $50,000 per year for outside assistance. Because we consider it a foundational educational matter (*i.e.*, one that is important to a basic understanding of U.S. business custom and practice) we consider those costs properly chargeable to the parent, without recharge to IUSA.

Affiliate Transactions

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III. Affiliate Transactions

A. Background

ISA conducts global operations under a complex structure employing a number of subsidiaries in many countries. IUSA itself comprises a variety of utility and non-utility entities. The three largest utility subsidiaries are NYSEG, RG&E, and CMP. The service company, Iberdrola USA Management Corporation (IUMC), comprises another principal IUSA subsidiary. IUMC provides common services to NYSEG, RG&E, and their IUSA affiliates. How well ISA manages these potentially complex international and domestic affiliate relationships in a manner that protects the interests of NYSEG's and RG&E's customers forms the subject of this chapter.

Liberty's investigation focused on the structures and controls established to prevent cross-subsidization by RG&E and NYSEG of their affiliates, assure arms'-length dealing, ensure that services provided by affiliates are effective, competitive, and priced in a nondiscriminatory fashion, and comply with public requirements and expectations. In conducting its assessment, Liberty reviewed and examined:

- The relationships and transaction paths among the affiliate service providers and beneficiaries
- The service agreements among the affiliates
- The nature of the shared services functions
- Inter-affiliate services billing
- Cost assignment methods and procedures
- Employee time and expense reporting
- The expatriate program.

Liberty also conducted a detailed review of a selected sample of individual affiliate transactions (the "transaction test") to verify that actual implementation of affiliate transaction policies and procedures conformed to policies, procedures, controls, and public requirements and expectations.

B. Findings

1. Affiliate Relationships

Liberty reviewed financial transactions among the New York utilities and their affiliates during 2009, 2010, and 2011. Our quantitative examination focused on the period from January 2009 through July 2011 (the "financial review period"). During this financial review period, NYSEG and RG&E engaged in affiliate transactions only with other U.S.-based affiliates, principally the other U.S. utilities and the service companies (EEMC and USS in 2009 and IUMC thereafter). A much smaller set of transactions with the U.S. parent (EEC in 2009 and IUSA thereafter) took place. The exclusively U.S. domestic nature of the affiliate transactions recently changed, with the adoption, on September 1, 2011, of service agreements between both NYSEG and RG&E and Iberdrola Energy Products, Inc. (IEP), a subsidiary of Spanish affiliate, Iberdrola Ingeniería y Construcción (I&C). NYSEG and RG&E indicated that expected sales from IEP were up to $2 million in 2011 and $8.5 million in 2012.

The following tables display monthly costs (invoiced during the financial review period) among the New York utilities and their affiliates in the amount of more than $1,000 annually. The affiliates involved include:

- The service companies – EEMC USS during 2009 and IUMC after 2009.
- The U.S. parent – Energy East during 2009 and IUSA after 2009.
- CMP
- Southern Connecticut Gas Company (SCG) (divested in 2010)
- Connecticut Natural Gas Corporation (CNG) (divested in 2010)
- Berkshire Gas Company (BGC) (divested in 2010)
- Maine Natural Gas Corp. (MNG)
- New Hampshire Gas Corp. (NHG)
- Energetix, Inc. (Energetix).

The Company sold the three southern New England gas companies (SCG, CNG, and BGC) to UIL Holdings in November 2010. Transactions with these companies involving NYSEG and RG&E continued after that period under a transition services agreement.

The Company also reported transactions among the New York companies and a few additional U.S.-based affiliates, but none amounted to more than $1,000 annually in 2009 and 2010. These include charges from:

- RG&E to NYSEG Solutions, Inc. during 2009
- RG&E to Cayuga Energy, Inc. during 2010
- NYSEG and RG&E to TEN Companies, Inc. during 2010.

Dollar Flows (in Thousands) to NYSEG from Affiliates

Month	RG&E			IUMC (USS in 2009)			EEMC			CMP			SCG		
	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net
Jan-09	581	55	526	2,712	18	2,694	751	86	665	2	-	2	1	1	-
Feb-09	1,381	763	617	2,531	4	2,527	1,590	186	1,404	10	9	1	-	-	-
Mar-09	999	249	750	2,646	33	2,614	2,019	442	1,578	1	1	-	4	4	-
Apr-09	822	216	605	3,012	26	2,986	1,044	223	821	2	2	-	-	-	-
May-09	788	152	636	2,542	1	2,541	1,001	21	980	1	1	-	-	-	-
Jun-09	1,003	402	601	2,510	6	2,504	1,393	349	1,044	-	-	-	-	-	-
Jul-09	845	305	540	2,698	9	2,689	4,245	3,350	895	-	-	-	-	-	-
Aug-09	989	195	794	2,690	44	2,646	1,207	105	1,102	-	-	-	-	-	-
Sep-09	751	161	589	2,052	6	2,046	1,945	339	1,606	-	-	-	-	-	-
Oct-09	1,063	442	620	2,634	4	2,630	1,384	209	1,175	0	0	-	1	1	-
Nov-09	725	108	617	2,328	13	2,315	966	129	836	(0)	(0)	-	9	9	-
Dec-09	4,624	4,041	583	4,409	23	4,386	7,154	9	7,145	152	152	0	54	54	-
Jan-10	779	197	581	2,774	(703)	3,477				-	-	-	-	-	-
Feb-10	840	269	571	3,358	56	3,303				-	-	-	8	4	4
Mar-10	3,026	1,629	1,397	4,631	79	4,552				24	24	-	1	1	-
Apr-10	638	107	532	2,987	190	2,798				-	-	-	1	1	-
May-10	1,037	579	458	4,504	43	4,461				-	-	-	10	2	8
Jun-10	706	245	461	6,480	1,333	5,147				1	1	-	7	1	6
Jul-10	670	180	490	6,139	1,377	4,762				-	-	-	8	1	7
Aug-10	1,057	498	559	5,996	765	5,231				1	-	1	10	1	8
Sep-10	2,039	1,421	618	2,994	72	2,923				23	1	21	13	4	10
Oct-10	1,311	510	801	4,207	286	3,921				32	11	21	9	3	6
Nov-10	1,514	886	629	1,991	258	1,733				43	10	33	9	7	2
Dec-10	2,132	1,485	647	3,881	191	3,690				56	37	19	-	-	-
Jan-11	969	222	747	2,875	173	2,702				23	-	23	-	-	-
Feb-11	784	132	652	3,972	169	3,803				31	1	29	0	0	-
Mar-11	1,136	93	1,043	3,060	33	3,027				34	5	29	-	-	-
Apr-11	729	79	650	2,857	250	2,607				53	23	30	-	-	-
May-11	945	106	839	3,155	45	3,110				85	0	84	-	-	-
Jun-11	1,261	131	1,129	4,141	83	4,058				68	5	62	-	-	-
Jul-11	1,009	87	922	6,762	2,470	4,291				39	13	26	-	-	-
Total	**37,151**	**15,945**	**21,207**	**109,528**	**7,353**	**102,175**	**24,698**	**5,448**	**19,250**	**679**	**297**	**382**	**143**	**92**	**50**

Note: Dollar flows from CNG & BGC, which were exclusively convenience payments are not included in table.
For the period shown (Jan. 2009 - July 2011), the total convenience payments amounted to:
$28K from CNG to NYSEG
$5K from BGC to NYSEG.

Dollar Flows (in Thousands) from NYSEG to Affiliates

Month	RG&E			IUMC (USS in 2009)			EEMC			IUSA (EEC in 2009)			CMP		
	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net
Jan-09	890	115	775	91	91	-	101	93	8	-	-	-	0	0	0
Feb-09	1,150	477	673	86	86	-	84	75	9	-	-	-	-	-	-
Mar-09	1,029	190	838	87	87	-	168	154	15	-	-	-	3	3	-
Apr-09	948	353	595	100	100	-	39	28	11	-	-	-	-	-	-
May-09	696	41	655	90	90	-	354	342	12	-	-	-	-	-	-
Jun-09	878	115	764	92	92	-	429	417	12	-	-	-	1	-	1
Jul-09	875	203	672	91	91	-	158	150	9	-	-	-	2	-	2
Aug-09	1,316	331	985	119	119	-	99	91	8	-	-	-	-	-	-
Sep-09	804	151	653	99	99	-	97	84	13	-	-	-	35	34	1
Oct-09	1,291	594	698	95	95	-	101	82	19	-	-	-	1	-	1
Nov-09	165	(491)	656	91	91	-	95	84	11	-	-	-	0	0	-
Dec-09	1,912	1,302	611	103	103	-	97	84	13	-	-	-	2	0	1
Jan-10	1,500	855	646	220	173	47				-	-	-	-	-	-
Feb-10	718	100	619	367	189	178				-	-	-	-	-	-
Mar-10	2,082	1,333	749	400	192	208				-	-	-	-	-	-
Apr-10	603	64	539	426	197	229				-	-	-	4	3	0
May-10	1,778	1,268	510	451	208	243				-	-	-	7	7	0
Jun-10	827	189	638	1,503	1,248	256				-	-	-	-	-	-
Jul-10	851	181	669	537	259	278				-	-	-	0	0	0
Aug-10	1,014	228	786	507	274	233				-	-	-	4	3	1
Sep-10	1,490	857	633	425	255	170				-	-	-	13	0	12
Oct-10	1,030	517	514	387	232	155				4	(11)	15	-	-	-
Nov-10	1,111	529	582	453	254	199				12	2	10	504	5	499
Dec-10	1,506	984	521	531	338	193				0	-	0	16	6	10
Jan-11	844	120	723	544	251	293				4	-	4	34	3	31
Feb-11	657	45	612	539	234	305				0	-	0	23	3	20
Mar-11	923	268	655	539	245	295				-	-	-	24	2	22
Apr-11	685	90	595	220	19	201				9	9	-	34	14	20
May-11	813	139	674	400	245	155				-	-	-	34	8	27
Jun-11	821	203	617	466	246	219				10	10	-	27	3	24
Jul-11	649	37	612	480	238	242				-	-	-	23	0	23
Total	**31,857**	**11,389**	**20,468**	**10,540**	**6,441**	**4,099**	**1,822**	**1,684**	**138**	**39**	**10**	**29**	**792**	**96**	**696**

Dollar Flows (in Thousands) from NYSEG to Affiliates (cont.)

Month	CNG			SCG			BGC			MNG			NHG		
	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net
Jan-09	5	0	5	8	0	7	2	0	2	-	-	-	-	-	-
Feb-09	5	1	5	10	1	9	2	0	2	-	-	-	-	-	-
Mar-09	6	0	6	11	0	10	2	0	2	-	-	-	-	-	-
Apr-09	5	0	5	7	0	7	2	0	2	-	-	-	-	-	-
May-09	7	0	6	6	0	6	3	0	2	-	-	-	-	-	-
Jun-09	5	0	5	7	0	7	3	0	3	-	-	-	-	-	-
Jul-09	5	0	4	5	0	5	2	0	2	-	-	-	-	-	-
Aug-09	7	0	6	6	0	6	2	0	2	-	-	-	-	-	-
Sep-09	6	1	5	5	0	5	2	0	2	-	-	-	-	-	-
Oct-09	6	1	5	7	1	5	2	0	2	-	-	-	-	-	-
Nov-09	7	0	6	8	0	7	2	0	2	-	-	-	-	-	-
Dec-09	5	0	5	7	1	6	2	0	2	-	-	-	-	-	-
Jan-10	7	0	6	9	0	9	2	0	2	-	-	-	-	-	-
Feb-10	7	0	7	10	0	9	2	0	2	-	-	-	-	-	-
Mar-10	7	0	7	7	0	7	3	0	2	-	-	-	-	-	-
Apr-10	8	1	6	7	0	7	2	0	2	-	-	-	-	-	-
May-10	5	1	4	4	0	4	1	0	1	-	-	-	-	-	-
Jun-10	4	1	4	4	0	4	1	0	1	-	-	-	-	-	-
Jul-10	5	0	5	5	0	4	2	0	2	-	-	-	-	-	-
Aug-10	5	0	4	4	0	3	2	0	2	-	-	-	-	-	-
Sep-10	4	0	4	4	0	3	1	0	1	-	-	-	-	-	-
Oct-10	5	0	5	4	0	4	2	0	2	-	-	-	-	-	-
Nov-10	4	0	4	4	0	4	1	0	1	1	-	1	-	-	-
Dec-10	8	2	6	4	0	4	2	0	2	10	1	8	0	-	0
Jan-11	34	27	8	9	-	9	3	0	3	6	-	6	1	-	1
Feb-11	2	-	2	1	-	1	1	-	1	6	-	6	1	-	1
Mar-11	-	-	-	-	-	-	-	-	-	6	-	6	1	-	1
Apr-11	-	-	-	-	-	-	-	-	-	6	-	6	1	-	1
May-11	0	-	0	0	-	0	-	-	-	7	1	6	2	-	2
Jun-11	-	-	-	-	-	-	-	-	-	8	-	8	0	-	0
Jul-11	-	-	-	-	-	-	-	-	-	7	-	7	4	-	4
Total	**174**	**40**	**135**	**163**	**11**	**152**	**52**	**2**	**49**	**57**	**2**	**55**	**9**	**-**	**9**

Dollar Flows (in Thousands) to RG&E from Affiliates

Month	NYSEG			IUMC (USS in 2009)			EEMC			CMP			SCG		
	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net
Jan-09	890	115	775	1,265	4	1,261	355	51	304	5	5	-	-	-	-
Feb-09	1,150	477	673	1,316	5	1,311	1,099	270	830	-	-	-	-	-	-
Mar-09	1,029	190	838	1,312	14	1,297	1,119	224	895	-	-	-	6	6	-
Apr-09	948	353	595	1,506	3	1,504	653	110	542	-	-	-	-	-	-
May-09	696	41	655	1,251	1	1,251	494	2	492	-	-	-	-	-	-
Jun-09	878	115	764	1,308	5	1,303	834	208	626	0	0	-	0	0	-
Jul-09	875	203	672	1,335	3	1,332	2,399	1,888	511	1	1	-	-	-	-
Aug-09	1,316	331	985	1,380	1	1,379	815	178	637	-	-	-	-	-	-
Sep-09	804	151	653	1,030	15	1,014	1,096	229	867	-	-	-	-	-	-
Oct-09	1,291	594	698	1,440	1	1,439	909	189	720	2	2	-	1	1	-
Nov-09	165	(491)	656	1,348	7	1,341	629	174	455	2	2	-	9	9	-
Dec-09	1,912	1,302	611	3,162	3	3,159	6,351	6	6,345	-	-	-	2	2	-
Jan-10	1,500	855	646	817	(478)	1,295				-	-	-	-	-	-
Feb-10	718	100	619	1,788	18	1,770				-	-	-	4	4	-
Mar-10	2,082	1,333	749	2,275	43	2,232				-	-	-	1	1	-
Apr-10	603	64	539	1,454	109	1,345				-	-	-	3	1	2
May-10	1,778	1,268	510	2,268	31	2,237				-	-	-	10	2	8
Jun-10	827	189	638	4,014	563	3,451				-	-	-	6	1	6
Jul-10	851	181	669	3,786	784	3,002				-	-	-	8	1	7
Aug-10	1,014	228	786	4,159	571	3,588				17	-	17	13	1	12
Sep-10	1,490	857	633	1,643	42	1,601				25	9	15	10	3	7
Oct-10	1,030	517	514	2,298	206	2,092				39	30	9	9	3	5
Nov-10	1,111	529	582	(305)	148	(453)				29	6	22	8	5	3
Dec-10	1,506	984	521	1,589	78	1,511				56	43	13	0	0	-
Jan-11	844	120	723	1,446	114	1,332				17	0	16	-	-	-
Feb-11	657	45	612	2,018	52	1,966				17	-	17	0	0	-
Mar-11	923	268	655	1,596	41	1,555				17	-	17	0	0	-
Apr-11	685	90	595	1,708	298	1,410				42	21	21	-	-	-
May-11	813	139	674	1,743	133	1,610				21	0	21	-	-	-
Jun-11	821	203	617	2,203	53	2,150				23	2	21	-	-	-
Jul-11	649	37	612	3,340	1,179	2,161				43	24	19	-	-	-
Total	**31,857**	**11,389**	**20,468**	**57,492**	**4,046**	**53,446**	**16,754**	**3,528**	**13,226**	**355**	**148**	**207**	**88**	**39**	**49**

Dollar Flows (in Thousands) from RG&E to Affiliates

Month	NYSEG			IUMC (USS in 2009)			EEMC			IUSA (EEC in 2009)		
	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net
Jan-09	581	55	526	249	249	-	12	9	3	12	12	-
Feb-09	1,381	763	617	128	128	-	13	9	4	-	-	-
Mar-09	999	249	750	203	203	-	15	14	1	-	-	-
Apr-09	822	216	605	162	162	-	20	20	-	-	-	-
May-09	788	152	636	158	158	-	16	15	1	-	-	-
Jun-09	1,003	402	601	165	165	-	11	11	-	-	-	-
Jul-09	845	305	540	158	158	-	56	56	-	-	-	-
Aug-09	989	195	794	159	159	-	12	12	-	-	-	-
Sep-09	751	161	589	158	158	-	12	11	1	-	-	-
Oct-09	1,063	442	620	163	163	-	12	12	1	-	-	-
Nov-09	725	108	617	157	157	-	17	11	6	-	-	-
Dec-09	4,624	4,041	583	157	157	-	17	11	6	-	-	-
Jan-10	779	197	581	261	175	87				-	-	-
Feb-10	840	269	571	306	186	120				-	-	-
Mar-10	3,026	1,629	1,397	336	188	147				7	7	-
Apr-10	638	107	532	320	195	125				-	-	-
May-10	1,037	579	458	343	199	144				-	-	-
Jun-10	706	245	461	1,150	998	153				-	-	-
Jul-10	670	180	490	352	183	169				-	-	-
Aug-10	1,057	498	559	356	187	169				-	-	-
Sep-10	2,039	1,421	618	381	259	122				-	-	-
Oct-10	1,311	510	801	358	200	158				2	-	2
Nov-10	1,514	886	629	396	188	208				1	0	1
Dec-10	2,132	1,485	647	455	253	203				23	23	-
Jan-11	969	222	747	351	179	172				-	-	-
Feb-11	784	132	652	341	175	165				-	-	-
Mar-11	1,136	93	1,043	343	189	154				-	-	-
Apr-11	729	79	650	521	377	144				-	-	-
May-11	945	106	839	319	205	114				-	-	-
Jun-11	1,261	131	1,129	304	178	126				6	6	-
Jul-11	1,009	87	922	353	254	99				-	-	-
Total	**37,151**	**15,945**	**21,207**	**9,563**	**6,785**	**2,778**	**215**	**193**	**22**	**53**	**50**	**3**

Dollar Flows (in Thousands) from RG&E to Affiliates (cont.)

Month	CMP			MNG			NHG		
	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net	Total Invoiced	Conv. Pays.	Net
Jan-09	-	-	-	-	-	-	-	-	-
Feb-09	-	-	-	-	-	-	-	-	-
Mar-09	-	-	-	-	-	-	-	-	-
Apr-09	-	-	-	-	-	-	-	-	-
May-09	4	1	3	-	-	-	-	-	-
Jun-09	-	-	-	-	-	-	-	-	-
Jul-09	-	-	-	-	-	-	-	-	-
Aug-09	13	13	-	-	-	-	-	-	-
Sep-09	-	-	-	-	-	-	-	-	-
Oct-09	-	-	-	-	-	-	-	-	-
Nov-09	-	-	-	-	-	-	-	-	-
Dec-09	-	-	-	-	-	-	-	-	-
Jan-10	-	-	-	-	-	-	-	-	-
Feb-10	-	-	-	-	-	-	-	-	-
Mar-10	15	-	15	-	-	-	-	-	-
Apr-10	32	21	12	-	-	-	-	-	-
May-10	17	3	14	-	-	-	-	-	-
Jun-10	18	4	14	-	-	-	-	-	-
Jul-10	19	6	13	-	-	-	-	-	-
Aug-10	28	3	25	-	-	-	-	-	-
Sep-10	38	17	20	-	-	-	-	-	-
Oct-10	45	25	20	-	-	-	-	-	-
Nov-10	37	9	28	0	-	0	1	-	1
Dec-10	27	4	24	0	-	0	1	-	1
Jan-11	31	1	30	0	-	0	1	-	1
Feb-11	42	3	39	1	-	1	1	-	1
Mar-11	35	1	33	1	-	1	2	-	2
Apr-11	33	-	33	1	-	1	2	-	2
May-11	39	0	39	1	-	1	3	-	3
Jun-11	29	3	26	0	-	0	3	-	3
Jul-11	53	24	29	1	-	1	3	-	3
Total	**554**	**138**	**417**	**4**	**-**	**4**	**18**	**-**	**18**

Note: Dollar flows to Energetix, CNG & SCG, which were exclusively convenience payments are not included in table.

For the period shown (Jan. 2009 - July 2011), the total convenience payments amounted to:
$268K from RG&E to Energetix
$169K from RG&E to CNG
$5K from RG&E to SCG.

The invoiced costs consist of labor charges, vendor invoices, employee expenses, journal entries, and convenience payments. The Company classifies as "convenience payments" all those transactions between affiliates, except those initiated within the service company, generated in manner other than through employee timesheets. Thus, any vendor invoice paid by RG&E or NYSEG that benefits one or more other affiliates is classified as a convenience payment. The same applies to any employee expenses, except for a relatively small number recorded directly in the time-entry system. The service company, on the other hand, can charge or allocate vendor invoices and employee expenses to affiliates through the month-end allocation process, although the Company classifies some vendor invoices paid by the service company as convenience payments on behalf of the affiliates.

NYSEG and RG&E have completed a limited amount of inter-affiliate asset transfers that are in addition to the cost flows shown in the preceding tables. These asset transfers have consisted of line devices, such as transformers, regulators, and capacitors, intended to meet business needs. The following table shows that most of these transfers have occurred between the two New York companies, with a small amount involving CMP.

Asset Transfers during 2009 and 2010

Company		Amount (in Thousands)	
From	**To**	**2009**	**2010**
RG&E	NYSEG	$15	$92
NYSEG	RG&E	$57	$15
CMP	RG&E	$5	-
CMP	NYSEG	$9	-

NYSEG and RG&E also provide tariffed electric and gas service to affiliates in their franchise territories.

2. Shared Service Functions and Service Agreements

Transactions between NYSEG or RG&E and their affiliates have been governed since 2002 by a Code of Conduct approved by the Commission. The currently effective New York Code of Conduct was developed pursuant to the Commission's September 9, 2008 order approving the acquisition of Energy East and the merger of NYSEG and RG&E into ISA. The current Code of Conduct, which the Commission adopted in June 2009, includes among its provisions the requirement for service agreements between the affiliates, rules for pricing affiliate transactions, rules for allocating the costs of affiliate transactions, and the requirement to file an annual Code of Conduct report. The Code of Conduct report summarizes the asset transfers, employee transfers, employee loans, cost allocations, affiliate transactions, and competitor or customer complaints related to conduct between the New York utilities and their affiliates during the past year. The Code of Conduct also contains a Schedule I, "Cost Allocation Guidelines for Affiliate Transactions," which specifies how inter-affiliate costs should be assigned.

IUSA petitioned the Commission on September 20, 2010 for an amendment to the Code of Conduct to allow I&C and other non-utility affiliates to participate in competitive bidding to provide services for NYSEG and RG&E. The Commission denied this petition in an order issued April 21, 2011, noting that the existing Code of Conduct allows I&C to provide services if the services "are priced at fully-loaded cost and the price is less than market price." On August 2, 2011, the Company filed NYSEG and RG&E service agreements with I&C subsidiary IEP, along with an accompanying summary form, as required by the Code of Conduct. The service agreements became effective September 1, 2011.

The following table shows the service agreements between NYSEG or RG&E and their affiliates and existing during 2009, 2010, and 2011.

NYSEG/RG&E Affiliate Service Agreements

Provider Company	Recipient Company	Agreement in		
		2009	2010	2011
EEMC	NYSEG	X	n/a	n/a
EEMC	RG&E	X	n/a	n/a
USS	NYSEG	X	n/a	n/a
USS	RG&E	X	n/a	n/a
IUMC	NYSEG	n/a	X	X
IUMC	RG&E	n/a	X	X
CMP	NYSEG	X	X	X
CMP	RG&E	X		X
IEP	NYSEG			X
IEP	RG&E			X
NHG	NYSEG			X
NHG	RG&E			X
NYSEG	EEMC	X	n/a	n/a
NYSEG	USS	X	n/a	n/a
NYSEG	IUMC	n/a	X	X
NYSEG	BGC	X	X	
NYSEG	Cayuga Energy		X	X
NYSEG	CMP			X
NYSEG	CNG	X	X	
NYSEG	Energetix			X
NYSEG	MNG			X
NYSEG	NHG			X
NYSEG	NYSEG Solutions			X
NYSEG	RG&E	X	X	X
NYSEG	SCG	X	X	
RG&E	EEMC	X	n/a	n/a
RG&E	USS	X	n/a	n/a
RG&E	IUMC	n/a	X	X
RG&E	CMP			X
RG&E	Energetix			X
RG&E	MNG			X
RG&E	NHG			X
RG&E	NYSEG	X	X	X
RG&E	NYSEG Solutions			X

The presidents of the provider and client companies typically sign these service agreements at the beginning of each year (the end of January or early February) in which inter-affiliate services are planned, unless a company contracts for the services during the year (as in the case of the IEP agreements). Generally the only change in the service agreements from year to year is in a table of annual estimates, derived from the annual budgeting process, of the costs of services to be provided.

The different agreements follow a standard form, and have largely the same content. Most differences among the agreements reside in Appendix A, which lists the services to be provided and, for most agreements, provides the cost assignment methods. The three basic types and corresponding formats for the agreements comprise:

- Service company as provider
- Utility as provider
- Non-utility affiliate as provider.

The language in Appendix A for the service-company-provider agreements is essentially identical to that of the Company's Cost Allocation Manual, except for an introductory section and different ordering of the Description of Services section in the Cost Allocation Manual. The Cost Allocation Manual also attaches a standard version of the service agreement. Appendix A of the service-company-provider agreements specifies that the service company will provide the following services to the client company:

- Accounting
- Audit
- Corporate Planning
- Executive
- Finance and Treasury
- Governmental Affairs
- Accounts Payable
- Human Resources
- Payroll
- Records Retention
- Regulatory Management
- Legal
- Other Corporate Support (including corporate communications)
- Transmission and Supply
- Distribution Operation
- Information Technology
- Supply Chain
- Customer Services
- Engineering Services
- Commodity Planning.

Appendix A provides for accumulation of costs in the accounting system, based on an internal order number. This order number determines whether the costs will be directly assigned or allocated, and how the direct assignment or allocation should be made. Indirect costs are to be charged in proportion to the directly assigned and allocated costs. Appendix A of the service-company-provider agreements lists 12 allocation methods to be used.

The utility-provider service agreements contain very similar provisions. The principal differences are the list of services, which is common across all the utility-provider agreements, and the cost assignment language. The specified utility-provider services are:

- Call center
- Customer billing
- Network support
- Telephone and voice
- Credit and collection
- Management support (including financial and administrative, corporate planning, legal, project management, government and legislative affairs, regulatory support, human resources administration, executive management and other management support services)
- Technical and operations (including engineering and planning, training, construction and facility management, maintenance, purchasing, billing, information services, environmental licensing and permitting, supply planning and transportation, energy services, and other operational or technical services).

The utility-provider service agreements list 14 cost-allocation methods for the costs, and specifies the allocator to use for each of the first five types of services listed above. However, the Company actually does not use allocation for any of the utility-provider costs, but directly charges all of them to the client companies.

The IEP agreements comprise the only cases of non-utility-provider agreements for NYSEG and RG&E. The other agreements specify that the services will be provided "at cost," but the IEP agreements specify that the services will be provided "at cost and below market, which require [IEP] to fairly and equitably charge direct fully-loaded costs for which it renders services to Client Company." The services are to be directly charged. Appendix A therefore does not provide cost-assignment methods but provides an extensive list of services to be provided in the following categories: assistance in the management and delivery of the utility's processes, system studies, scheduling, environmental assessment, permitting and regulatory, mapping services, property acquisition, specifications and electrical study works, procurement service, safety program plans, community relations plans, construction planning and supervision, project commissioning plans, project close-out plans, schedule management, cost management, estimating, risk management, quality management plan, performance compliance, project information systems and documentation, and transition plan.

The sale of the southern New England gas companies (CNG, SCG, and BGC) to UIL Holdings on November 16, 2010 included an agreement under which IUSA was to continue providing services to the Southern New England gas companies. A Master Transition Services Agreement (TSA) between IUSA and UIL Holdings covered these services. This agreement contains language largely identical to the service agreements between IUMC and its affiliate companies regarding services to be performed, cost assignment and allocation, and billing. There are no provisions for direct billing of the services provided by NYSEG, RG&E, or other utility affiliates for the Southern New England gas companies during the effective period of the TSA. However, the Company has indicated that although only IUMC is required to prepare service agreements with CNG, SCG, and BGC, it considers all other activity between these companies and IUMC affiliates to be covered by the TSA. It also indicated that "all groups are encouraged to charge these companies directly for any applicable expenses."

3. Inter-Affiliate Billing

The ISA affiliates exchange invoices for intercompany transactions each month. The IUMC assistant controller's Control and Administration group reviews the intercompany accounts receivable and accounts payable by operating company to ensure the billing statements provided to the companies agree with the amounts direct charged or allocated on each company's books. The Financial Control and Administration group also reviews the data for anomalies, trends, and consistency with prior periods.

The affiliate company controllers receive the billing statement via e-mail in PDF file format, with an attached request for electronic funds transfer form, should the controller approve the invoice. Supporting documentation attached to the billing statement helps to explain the charges. The service agreements indicate that the companies have 30 days to pay the bill from the date of invoice and that there will be 0.5 percent late payment fee for every month there is an outstanding balance. After the affiliate controller approves the invoice, service company personnel generate a check request, with all the appropriate accounting codes and approvals, and submit it to the treasury department for payment. Payments occur through an electronic transfer of funds between the companies' bank accounts.

The service-company accounting personnel manage the intercompany receivables and payables; the treasury group is responsible for the cash management function. IUSA has a money pool for non-utility subsidiaries to process vendor payments, payroll, and intercompany transactions. The utilities participate in no money pool.

4. Cost Assignment Methods and Procedures

IUSA uses an SAP Enterprise Resource Planning (ERP) system for most of its subsidiaries. The first implementation of the SAP ERP system was by RG&E in 2001. Other affiliates, including NYSEG, CMP, CNG, and SCG, implemented the system in 2004, following the EnergyEast merger. More recently, in October 2010, a final set of companies, including NHG and MNG, transitioned to SAP.

SAP handles most of the financial processing and reporting, including assigning and allocating costs as part of the month-end book-close process. The Company uses a few non-SAP subsidiary systems for special purposes. PowerPlant, for example, is a non-SAP system, which the Tax Department uses for tax calculations. The SAP accounting-code structure is designed to enable both external and internal reporting requirements. The structure includes coding for sending and receiving companies, sending and receiving cost and profit centers, cost objects, activity type, projects, and general ledger accounts, among others. The system identifies projects through the "cost collector" codes; *i.e.*, Internal Order (I/O) codes or, for capital projects, Work Breakdown Structure (WBS) codes.

The service company and operating companies have their own income statements and balance sheets in SAP. There exist capabilities to "drill down" to view such lower-level data as sub-accounts, cost objects, cost centers, and projects. The operating companies only have drill-down capabilities for their own company, which guards against one company's viewing another company's detail. Both the operating companies and the service company can have capital assets on their books, although services using operating company assets can be provided by the service company. For example, specific servers may be on the operating company's books although the support for these servers is provided by the service company Information Technology group as a shared service.

The SAP system provides electronic access to vendor invoices, purchase orders, and time entry (but not payroll). An optical reader scans invoices and the supporting documentation; the Company then archives them for future retrieval and use. The scanning process began in 2009 and, with the exception of those from the first quarter of 2011 (during which there was a problem with the optical reader), all invoices have been scanned into SAP since the start of this process.

The service agreements contain provisions providing for accumulation of costs in the accounting system based on an Internal Order number. That number, in combination with other accounting codes, determines whether the costs will be directly assigned or allocated. Indirect costs are to be charged in proportion to the directly assigned and allocated costs. The service agreements identify three types of Internal Orders:

- Those for services specifically performed for a single client, which will be directly assigned to that client.
- Those for services specifically performed for two or more clients, which will be distributed among the clients using methods determined on a case-by-case basis, consistently with the nature of the work performed or based on one of the allocation methods specified in the next section.
- Those for services of a "general nature, which are applicable to all Client Entities." These are to be billed using the global allocation factor.

The service agreements under which IUMC acts as provider specify that the employees will charge time on a daily basis. Department supervisors must review and approve the time sheets. The Company maintains the time records for three years. The wages of employees, such as administrative assistants and secretaries, who generally assist employees who provide services directly to system companies, will be allocated based on the allocation of the wages of the employees they assist.

Appendix A to the service agreements outlines the methods and procedures used for assignment of the costs of affiliate transactions. The Company also operates under a Cost Manual describing the assignment of service company costs. The manual contains essentially identical language to Appendix A of the service-company-provider service agreements. The IUMC Assistant Controller's Administration Group maintains the cost manual, and has responsibility for the related policies and procedures.

The service agreements specify the following cost allocators for costs from IUMC:

- Number of Employees Ratio
- Accounts Payable Ratio
- Number of Customers Ratio
- Global Allocation Factor
- Regulated Global-8 (also called Regulated 8)
- Regulated Global-6 (also called Regulated 6)

- Regulated Global-5 (also called Regulated 5)
- Regulated Global-4 (also called Regulated 4)
- Commodity – Energy Supply Transaction System Allocation Factor
- Commodity – Global Allocation Factor
- Commodity – Regulated Gas Allocation Factor
- Electric Allocation Factor.

The Global, Regulated Global, and Electric allocation factors operate as general allocators, using the so-called Massachusetts Formula, which bases the allocation on an average of gross plant, gross payroll charges, and gross revenues during the previous calendar year. The Global allocator applies this formula to the broadest range of affiliates, including both utility and non-utility companies. The Regulated Global allocators apply the Massachusetts Formula to subsets of the regulated utilities:

- Regulated 8: NYSEG, CMP, SCG, CNG, RG&E, BGC, MNG, and NHG
- Regulated 6: NYSEG, CMP, SCG, CNG, RG&E, and BGC
- Regulated 5: NYSEG, CMP, SCG, CNG, and RG&E
- Regulated 4: NYSEG, CMP, SCG, and CNG.

The Electric Allocation Factor allocates to the electric portion of NYSEG, RG&E, and CMP under the Massachusetts Formula.

Liberty found no cases during the period studied (January 2009 through July 2011) in which IUMC allocations used Regulated 4, which excludes RG&E from the allocation. The sale of the Southern New England gas companies in November 2010 brought adoption of new versions of the Global and Regulated allocators that exclude these companies from the allocations.

The remaining service-company allocators are cost-causative (*i.e.*, based on factors related to the work function being allocated, such as employee headcount for human resource costs):

- The Number of Employees Ratio is based on the actual count of applicable employees at the end of the previous calendar year.
- The Accounts Payable Ratio is based on the actual count of invoices processed at the end of the previous calendar year.
- The Number of Customers Ratio is based on the average annual customer count.
- The Commodity – Energy Supply Transaction System Allocation Factor is to be used to allocate the cost of managing the Energy Supply Transaction System. It is based on the proportion of the gas and/or electric supply costs attributable to each entity.
- The Commodity – Global Allocation Factor is to be used to allocate the cost of commodity planning, procurement, and sale when the service applies to all companies, regardless of whether they are gas, electric, or combined gas/electric companies. It is also based on the proportion of gas and/or electric supply costs.
- The Commodity – Regulated Gas Allocation Factor is to be used to allocate costs for gas commodity planning, procurement, and sale for regulated gas utility companies. It is based on the proportion of the gas supply costs attributable to each gas utility.
- The Electric Allocation Factor is to be used to allocate costs for the coordination and direction of electric transmission issues for the benefit of regulated electric utilities. It uses the same data as the global allocation but is limited to data of the electric utilities.

Liberty found no cases during the period studied (January 2009 through July 2011) in which IUMC allocations used the Accounts Payable or Number of Customers ratios. The Company confirmed that it only uses the headcount-based and commodity-usage cost-causative allocation factors. The Company did update the cost manual in 2010 to remove the Accounts Payable and Number of Customers ratios, and to make a few other wording changes. However, the 2010 and 2011 IUMC service agreements with NYSEG and RG&E still include the old list of allocators shown above.

The utility-provider service agreements also include extensive descriptions of cost allocation approaches, including a list of 14 different allocators to use. They even specify that the costs of certain functions will be assigned using specific allocators:

- Call center; “These costs are allocated using the call center ratio.”
- Customer billing; “These costs are allocated using the customer-billing ratio.”
- Network support; “These costs are allocated using the LAN/Wan service ratio.”
- Telephone and voice; “These costs are allocated using the telephone and voice service ratio. This excludes actual usage that is billed to the client entity.”
- Credit and collection; “These costs are allocated using the customer-billing ratio.”

Nevertheless, the Company has indicated that all costs for utility-provided services are directly assigned, and not allocated. Only the service company can allocate costs to other affiliates. The Company indicated that the allocation language is found in the utility-to-utility service agreements because these agreements use generic language.

The utility-provider and service-company-provider service agreements and the service-company cost manual state that costs “that can be directly attributed to direct charges,” *i.e.*, Administrative and General (A&G) overhead, are allocated in proportion to the direct charges or other appropriate cost allocations. The agreements list the following types of overhead costs:

- Payroll (pension, benefits, time not worked, payroll taxes), with the rate computed by dividing monthly payroll overhead expenses by monthly base labor dollars
- Common Asset Usage (cost of furniture and desktop equipment), with the rate computed by dividing the economic carrying costs of the assets by the total actual labor dollars of employees using those assets
- Occupancy (cost workspace occupied by employees), with the rate computed by dividing the economic carrying costs for the buildings by the total actual labor dollars of employees working in those buildings
- Management, with the rate based on the ratio of supervisory wages to all other wages
- Administrative and General Support Adder, an “alternative” allocation to be used “in place of other specific administrative and general support overheads and is added to total costs of client services.” The purpose of the adder is “to recover indirect administrative and general expenses incurred and not otherwise charged directly to these clients for certain activities.” It includes office facility costs like furniture and office equipment used in performing administrative functions. The company has indicated that it does not use this allocation method.

The IUMC Control and Administration group reviews and develops the allocation factors, and inputs them into SAP early in each year. The following tables show the allocation percentages used during 2009, 2010, and 2011. The most significant change in the allocators during this period resulted from the gas-company sale in late 2010. The sale caused the use of new general (Massachusetts Formula) allocators not listed in the service agreements. These were calculated for use by IUMC departments who were not supporting the companies during the transition service agreement. They are referred to as:

- "Global Factors Post Sale," which is Global Factors without the Connecticut companies
- "New Reg Global 5," which is Reg Global 8 without the Connecticut companies
- "Reg Global 3," which is Reg Global 5 without the Connecticut companies.

Allocation Factor Percentages 2009

COMPANY	Electric	Gas Supply	Commodity	Reg Global 8	Reg Global 5	Reg Global 6	Global Factors	Benefit Employee	Regulated Employee	All Employees
Energy East							13.99%	0.11%		0.11%
Energetix			6.17%				1.41%	0.53%		0.53%
CNE Energy Service Group							0.05%			
Union Water Power							0.03%	0.01%		0.02%
Maine Com							0.02%			
The Ten Companies							0.72%	0.58%		0.58%
Berkshire Gas Company		4.12%	1.66%	2.03%		2.03%	1.68%	2.34%	2.37%	2.33%
The Energy Network							0.11%			0.07%
Iberdrola USA Solutions			11.18%				1.84%			0.13%
Cayuga Energy							0.13%			0.02%
New Hampshire Gas			0.08%	0.07%			0.06%	0.15%	0.15%	0.15%
Maine Natural Gas		0.63%	0.26%	0.23%			0.18%	0.16%	0.17%	0.16%
RGE	23.29%	23.27%	19.65%	22.86%	23.39%	22.93%	18.48%	18.00%	18.23%	17.96%
NYSEG	52.85%	24.97%	36.65%	43.96%	45.03%	44.10%	35.92%	44.25%	44.79%	44.16%
MEPCO							0.10%			
Chester							0.08%			
SCG		21.39%	8.63%	7.33%	7.50%	7.35%	6.03%	5.92%	6.00%	5.91%
CMP	23.86%		5.38%	15.74%	16.12%	15.79%	12.76%	21.74%	22.00%	21.67%
CNG		25.62%	10.34%	7.78%	7.96%	7.80%	6.41%	6.21%	6.29%	6.20%
Grand Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Allocation Factor Percentages 2010

COMPANY	Electric	Gas Supply	Commodity	Reg Global 8	Reg Global 5	Reg Global 6	Global Factors	Benefit Employee	Regulated Employee	All Employees	New Reg Global 5	Reg Global 3	Global Factors Post Sale
Iberdrola USA, Inc.							11.37%	0.09%		0.09%			12.72%
Energetix			5.43%				1.37%	0.52%		0.52%			1.64%
CNE Energy Service Group							0.06%						0.07%
Union Water Power							0.02%	0.02%		0.02%			0.02%
Maine Com							0.02%						0.03%
The Ten Companies							0.68%	0.60%		0.60%			0.79%
Berkshire Gas Company		3.40%	1.35%	1.79%		1.80%	1.53%	2.37%	2.40%	2.37%			
The Energy Network							0.05%			0.06%			0.05%
Iberdrola USA Solutions			10.83%				1.58%			0.19%			1.90%
Cayuga Energy							0.11%			0.02%			0.13%
New Hampshire Gas			0.09%	0.07%			0.06%	0.15%	0.15%	0.15%	0.09%		0.08%
Maine Natural Gas		0.77%	0.30%	0.24%			0.19%	0.13%	0.13%	0.13%	0.29%		0.23%
RGE	23.38%	23.75%	22.64%	22.85%	23.34%	22.93%	19.13%	18.16%	18.38%	18.11%	27.36%	27.47%	22.33%
NYSEG	52.30%	28.39%	37.51%	44.37%	45.34%	44.51%	37.71%	44.09%	44.64%	43.96%	52.99%	53.18%	43.99%
MEPCO							0.10%						0.12%
Chester							0.08%						0.09%
SCG		19.97%	7.91%	7.12%	7.27%	7.14%	6.05%	5.92%	6.00%	5.91%			
CMP	24.32%		4.55%	16.18%	16.53%	16.23%	13.62%	21.69%	21.96%	21.63%	19.28%	19.35%	15.84%
CNG		23.72%	9.39%	7.37%	7.52%	7.39%	6.27%	6.26%	6.34%	6.24%			
Grand Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Allocation Factor Percentages 2011

COMPANY	Electric	Gas Supply	Commodity	Reg Global 3	Reg Global 5	New Reg Global 5	Global Factors Post Sale	Global Factors	Benefit Employee	Regulated Employee	All Employees
Iberdrola USA, Inc.							12.87%	11.44%	0.13%		0.13%
Energetix			8.13%				1.49%	1.25%	0.67%		0.67%
CNE Energy Service Group							0.14%	0.12%			
Union Water Power							0.02%	0.01%			
Maine Com							0.03%	0.02%			
The Ten Companies							0.72%	0.62%	0.78%		0.77%
Berkshire Gas Company								1.61%			
The Energy Network							0.12%	0.10%			0.35%
Iberdrola USA Solutions			12.48%				2.01%	1.68%			
Cayuga Energy							0.15%	0.13%			
New Hampshire Gas			0.11%			0.09%	0.08%	0.07%	0.21%	0.22%	0.21%
Maine Natural Gas		0.33%	0.24%			0.25%	0.19%	0.17%	0.16%	0.16%	0.16%
RGE	22.75%	35.27%	25.65%	26.79%	22.81%	26.70%	21.68%	18.63%	22.26%	22.61%	22.18%
NYSEG	51.98%	64.40%	49.21%	52.74%	45.00%	52.56%	43.49%	37.33%	51.61%	52.44%	51.43%
MEPCO							0.13%	0.12%			
Chester							0.08%	0.08%			
SCG					7.24%			5.99%			
CMP	25.27%		4.18%	20.47%	17.53%	20.40%	16.80%	14.47%	24.18%	24.57%	24.10%
CNG					7.42%			6.16%			
Grand Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

5. Employee Time and Expense Reporting

During the audit period, the Company was in the process of moving all employees to use of a self-service web-based portal for reporting time directly into the SAP financial system. The Company previously used a centralized time-reporting process, through which time keepers recorded time for groups of employees. As of the July 2011, most employees of IUSA and its subsidiaries were using the self-service system. Approximately 1,000 NYSEG bargaining-unit employees remained to move to the new system, and are scheduled to do so in the next few months.

The self-service system has two modules. Employees use the Employee Self-Serve (ESS) module for all time entry, including hours worked and non-productive time, such as vacation and sick time. Supervisors and managers use the Manager Self-Serve (MSS) module to approve the time reports for their direct reporting personnel. All employees are required to enter their time and have it approved by their immediate supervisor. There is no default time reporting for any employees. With some minor exceptions, all salaried employees are paid on a bi-weekly basis; non-salaried (bargaining unit) employees are paid on a weekly basis.

The Company has no mechanized method for most employee expense reporting. It issues corporate credit cards to employees, which are intended to be used for most employee expenses. Employees use paper forms to reconcile the credit card statements, record out-of-pocket expenses for reimbursement, and charge the expenses to the appropriate accounts. The only mechanized expense recording is for personal automobile mileage and per diems charged during travel, which employees input through the time-recording process directly into the SAP system. The Company plans to include more travel reimbursement capabilities into SAP in the future.

6. Expatriate Program

The International Mobility Program operates as a component of the Company's professional development and talent management program. It provides international assignments for selected employees. For IUSA, this includes: (a) international employees hosted by one of the U.S. affiliates, and (b) U.S. employees hosted by an international affiliate. The Human Resources department manages the program centrally.

The Company provides two categories of assignments:

- Standard International Assignments, which are intended for employee development and international knowledge sharing. In these assignments, the employees work for two to three years in a company in the host country, while remaining employees of the home country. The Company also refers to the Standard International Assignment program as Professional Development.
- International Graduate Program, which is intended for new hires just graduated from college, chosen to gain experience in another country. Unlike the Standard International Assignment program, these employees work for two years in the host country and become employees of the host company.

The International Graduate Program provides fewer benefits to employees than do the Standard International Assignments.

The following table shows the numbers of employees who participated in the program by category since IUSA first began to participate in the program in 2009 through June 2011.

Number of International Assignments to and from the U.S.							
Assignment Start Year	**Non-U.S. Employee Assigned in U.S.**			**U.S. Employee Assigned outside U.S.**			**Total**
	Standard	**Graduate Program**	**Total**	**Standard**	**Graduate Program**	**Total**	
2009	1	0	1	0	0	0	1
2010	7	2	9	2	2	4	13
2011	3	1	4	1	0	1	5
Total	11	3	14	3	2	5	19

Through the middle of 2011, relatively few International Program participants had been assigned to or from the U.S. They included 14 Spanish and other international employees hosted in the U.S. and 5 U.S. employees hosted in Spain. As of June 2011, four of the employees on Standard International Assignments had completed their assignments (one in 2010, the remainder in early 2011). At that point, 15 employees served in international assignments:

- 8 non-U.S. employees on a Standard International Assignment in a U.S. host company
- 3 non-U.S. employees in the Graduate Program working in a U.S. host company
- 2 U.S. employees on a Standard International Assignment in a non-U.S. host company
- 2 U.S. employees in the Graduate Program in a non-U.S. host company.

IUMC has hosted 10 of the expatriates. NYSEG and RG&E have each hosted two expatriates. All international assignments for the U.S. employees have been at ISA.

7. Financial Transaction Testing

Liberty's transaction test sought to review examples of actual transactions during the audit period, and compare their treatment to the Company's stated and documented policies and procedures. The primary inputs to the accounting system are:

- Employee time reports
- Accounts payable invoices and other related documents
- Journal entries (used mainly for adjustments)
- Employee expense reports.

Liberty chose examples from each of these four transaction types. Convenience payments formed a significant number of transactions observed in the aggregate financial data. Liberty therefore also included convenience payments in the test transactions. The test included transactions from four specific months during the audit period: June 2009, June 2010, December 2010, and June 2011. Liberty chose the test transactions from among a list provided by the Company of all transactions involving RG&E and NYSEG during the four test months.

The test contained a total of 95 transactions chosen from the four test months. The test transactions included transactions from IUMC to the New York companies, and also transactions from the New York companies to IUMC and transactions between the New York companies and other affiliates. Most test transactions were from June 2010. Liberty concentrated mainly on higher value transactions, but included a few smaller-value transactions of particular interest, such as ones involving expatriates. We divided the labor transactions between those for which the subject of the examination was the treatment of the worked time and those concentrating solely on the treatment of the overheads. Nine of the labor transactions involved overheads only.

For each test transaction, Liberty asked the IUMC Assistant Controller's organization to provide source data (such as, labor files, purchase orders, invoices, and journal entry sheets) to support the accounting of the transactions, including the cost assignment. After analyzing the source data provided, Liberty submitted several rounds of questions about the transactions to the Company. By the end of the test, the Company provided sufficient information for Liberty to draw final conclusions about most test transactions.

Based on the Company's responses, Liberty found that the Company had misclassified the type of one of the June 2011 transactions in the original transaction lists, which required dropping it from the test. This deletion left a total of 94 that Liberty reviewed in detail. The following table shows the distribution of the final 94 test items by transaction type. Because the Company uses an outside credit card vendor for most employee expenses, the test transactions Liberty designates as "employee expenses" in this table are actually a form of an accounts payable transaction. The "accounts payable" numbers represent the remainder of the accounts payable test transactions.

Number of Test Transactions by Type					
Month	Labor	Accounts Payable	Journal Entries	Employee Expenses	Total
Jun-09	1	1	0	0	2
Jun-10	25	29	8	7	69
Dec-10	7	4	1	0	12
Jun-11	6	3	1	1	11
Total	39	37	10	8	94

Of these transactions:

- 51 originated in IUMC
- 19 originated in NYSEG
- 19 originated in RG&E
- 6 originated in other affiliates (one transaction involve a project with charges from both RG&E and CMP to NYSEG)
- 18 of the accounts payable and employee expense transactions were classified by the Company as convenience payments, 7 of which were from IUMC to NYSEG or RG&E and the remainder originated in NYSEG, RG&E, or another utility
- 21 were transactions between NYSEG and RG&E
- 9 were transactions from NYSEG or RG&E to IUMC
- 9 were transactions between NYSEG or RG&E and other utilities, including CMP, SCG, CNG, BGC, MNG, and NHG.

C. Conclusions

1. NYSEG and RG&E engage in a significant amount of affiliate transactions. Support from the service company and work on behalf of each other comprise most of the dollar amount of these transactions, but the fraction involving other affiliates has been growing.

The following summary table shows that invoices for transactions between NYSEG or RG&E and other affiliates amounted to over $100 million annually in 2009 and 2010. Excluding the convenience payments ("CPs"), the transactions amounted to slightly less than $100 million annually. A significant portion of the transactions appears to be related to the Company's matrix management structure. This is particularly true of the transactions between NYSEG and RG&E, which share many functions, but also contributes to the services provided by the service company because top management of lines of business and functional areas are typically service company employees. Liberty's transaction test provided examples where NYSEG or RG&E shared functions with utility affiliates outside of New York. The Company has indicated that these transactions among the affiliate utilities include such functions as remittance processing, operational support, and specialty support related to legal and regulatory services.

Affiliate Invoices to and from NYSEG and RG&E (in Thousands)						
	All Affiliates		From Service Companies		Between NYSEG and RG&E	
Year	**Total**	**Net of CPs**	**Total**	**Net of CPs**	**Total**	**Net of CPs**
2009	$124,368	$99,040	$91,869	$82,646	$26,523	$16,053
2010	$118,890	$90,174	$75,728	$69,668	$30,260	$15,150
2011 (thru July)	$60,021	$49,851	$40,875	$35,783	$12,225	$10,472
Total	$303,280	$239,066	$208,472	$188,098	$69,008	$41,675

During Liberty's financial review period (January 2009 through July 2011):

- Most of the invoices are from the service companies to either NYSEG or RG&E (74 percent in 2009 and 64 percent in 2010; 84 percent in 2009 and 77 percent in 2010, net of convenience payments).
- The payments between NYSEG and RG&E comprise the next largest fraction of affiliate transactions (21 percent in 2009 and 25 percent in 2010; 16 percent in 2009 and 17 percent in 2010, net of convenience payments).
- The fraction contributed by other types of affiliate transactions has been growing. In 2009, this fraction was only 4.6 percent (0.3 percent, net of convenience payments). This fraction grew to 10.8 percent (6.0 percent, net of convenience payments) in 2010. It was 11.5 percent (7.3 percent, net of convenience payments) for the period from January through July 2011.
- Transactions from NYSEG or RG&E to IUMC comprise the largest fraction of these other affiliate transactions.
- Most of the remaining transactions are labor on behalf of other utilities, mainly involving CMP, but also the southern New England gas companies (SCG, CNG, and BGC), which IUSA has recently divested, and, beginning in late 2010, a small amount involving the northern New England gas companies (MNG and HNG).
- The only other substantial transactions during the financial review period involving a non-utility affiliate were from RG&E to Energetix, all of which were classified as "convenience payments."
- NYSEG and RG&E charge some costs directly to the U.S. parent (IUSA), but these transactions are relatively small in magnitude. The data show no charges directly from IUSA to either NYSEG or RG&E.

The Company confirmed that as of June 2011, there had been no charges to RG&E or NYSEG from non-U.S. affiliates, including the corporate parent, ISA. All charges from ISA or non-U.S. affiliates were recorded solely at the U.S. holding company, IUSA. This was to change after the September 2011, when NYSEG and RG&E signed service agreements with IEP to provide services.

The following table shows the costs (net of convenience payments) charged to NYSEG and RG&E by functional area. As the company noted, the data display some inconsistencies in the data provided to Liberty. Thus, there are some minor discrepancies between the numbers in this table and some others in this report.

Service Company Charges by Functional Area (in Thousands)								
Functional Area	***2009***				***2010***			
	RG&E	***NYSEG***	***Total***	***Percent***	***RG&E***	***NYSEG***	***Total***	***Percent***
CEO	$6,451	$7,252	$13,703	16.9%	$647	$5,350	$5,996	8.6%
COO	$125	$195	$320	0.4%	$3,225	$2,672	$5,898	8.5%
Legal	$1,013	$1,825	$2,838	3.5%	$642	$1,570	$2,212	3.2%
HR	$2,819	$5,844	$8,663	10.7%	$2,631	$5,697	$8,328	11.9%
Public Affairs	$13	$43	$57	0.1%	$24	$18	$42	0.1%
IT	$11,802	$24,268	$36,070	44.4%	$10,232	$20,636	$30,868	44.3%
General Services	$976	$1,885	$2,861	3.5%	$891	$1,721	$2,612	3.7%
CFO	$6,250	$8,701	$14,951	18.4%	$4,748	$7,616	$12,363	17.7%
Internal Audit	$548	$562	$1,110	1.4%	$281	$515	$795	1.1%
Regulatory	$280	$425	$706	0.9%	$292	$325	$617	0.9%
Total	$30,278	$51,000	$81,278	100.0%	$23,612	$46,118	$69,731	100.0%
Functional Area	***Jan. - July 2011***				***Jan. 2009 - July 2011***			
	RG&E	***NYSEG***	***Total***	***Percent***	***RG&E***	***NYSEG***	***Total***	***Percent***
CEO	$423	$1,203	$1,627	4.5%	$7,521	$13,805	$21,325	11.4%
COO	$1,300	$1,996	$3,295	9.2%	$4,650	$4,863	$9,513	5.1%
Legal	$224	$525	$748	2.1%	$1,878	$3,920	$5,798	3.1%
HR	$1,391	$2,492	$3,883	10.9%	$6,842	$14,033	$20,875	11.2%
Public Affairs	$15	$30	$46	0.1%	$53	$91	$144	0.1%
IT	$5,319	$10,916	$16,235	45.4%	$27,353	$55,820	$83,173	44.5%
General Services	$685	$1,359	$2,044	5.7%	$2,553	$4,965	$7,518	4.0%
CFO	$2,358	$4,423	$6,781	19.0%	$13,355	$20,740	$34,096	18.3%
Internal Audit	$179	$303	$482	1.3%	$1,008	$1,380	$2,388	1.3%
Regulatory	$289	$351	$640	1.8%	$861	$1,101	$1,962	1.1%
Total	$12,184	$23,599	$35,783	100.0%	$66,074	$120,718	$186,792	100.0%

As can be seen, across the entire period from January 2009 through July 2011:

- By far the largest contribution to the service-company costs (45 percent) is from the information technology (IT) groups.
- Other large contributors are the financial and accounting groups (CFO), contributing 18 percent of the costs, and human resources (HR), contributing 11 percent. The fraction of costs contributed by these three groups has remained fairly constant from 2009 through the middle of 2011.
- The executive groups (CEO and COO) were also significant contributors, averaging 17 percent of the costs over the entire period. During this period, the CEO function has declined from 17 percent during 2009 to 5 percent in the first half of 2011, while the COO groups' contribution has increased from a negligible fraction in 2009 to 9 percent during the first half of 2011.

2. **IUSA categorizes as "convenience payments" some transactions that are actually associated with services performed by one affiliate on behalf of another.** *(Recommendation #1)*

Convenience payments, as the Company defines the term, constitute 22 percent of the inter-affiliate billing to and from NYSEG and RG&E during 2009 and 2010. After removing the service-company charges (*i.e.*, including only the utility-originated billing), the convenience-payment fraction rises to 50 percent of all charges in 2009 and 52 percent in 2010. The company classifies these amounts as convenience payments in the inter-affiliate invoices.

The Company uses a fairly expansive interpretation of what constitutes a "convenience payment." The Company explained:

> *Convenience Charges or Convenience payments are defined as any affiliate transactions that are booked directly on an affiliate's books and [do] not flow through the IUMC month end settlement process. All other affiliates' convenience charges or convenience payments are classified as any affiliate transaction that does not flow through the SAP [financial system] timesheet process. There is no mechanism in SAP for affiliates to allocate expenses other than through timesheet transactions.*
>
> *In summary all affiliate transactions are classified as either a settlement in SAP or a convenience charge/payment.*

As a consequence of this definition, IUSA classifies as convenience payments all transactions between affiliates, except those initiated within the service company, that are generated in any other manner than through employee timesheets.

The term "convenience payment" is usually understood to refer to pass-through costs that represent no material work performed by an affiliate on behalf of another. Instead, they are typically payments made by one affiliate on behalf of another that are unrelated to any services that the affiliate provides. A typical example is the case of a vendor, such as an insurance company, that provides services to multiple affiliates but which, for convenience, sends the invoice to only one of the affiliates. The invoiced affiliated pays the invoice and bills each other affiliate for the amount of the invoice that applied to it. Such payments are usually, but not always, made by the service company on behalf of other affiliates. However, for complex public utility holding companies like ISA, it is not uncommon for one of the non-service-company affiliates to make convenience payments on behalf of others. As noted above, this is indeed the case for payments involving NYSEG and RG&E.

However, IUSA lumps together with such payments normally understood to be convenience payments certain payments that are associated with services performed by one affiliate on behalf of another. The Company treats all transactions between non-service company affiliates that are not initiated through the time-entry system as convenience payments. This includes labor transactions, use of fleet vehicles, and a small portion of employee expenses (personal automobile mileage and per diems). Thus, any payment to a consultant or contractor working on a project that an affiliate performs on behalf of another is treated as a convenience payment. As Liberty observed during the transaction test, even some service-company invoices related to service performed by service company employees on behalf of an affiliate are treated as convenience payments.

Section 1.1 of the service agreements, including the utility-provider agreements, states that the provider company "may arrange, where it deems appropriate, for the services of such experts, consultants, advisers, and other persons with necessary qualifications as are required for or pertinent to the provision" of the services. However, using IUSA's definition of a convenience payment, the cost of services of any outside consultant or other outside contractor used in the providing of any services from one non-service-company affiliate to another is classified as a convenience payment, because this cost enters SAP as an invoice rather than through time-entry.

The Company has indicated that its goal is to eliminate convenience payments between operating companies and restrict them to the service company, and introduced a policy change in November 2010 to accomplish this change. The service company uses a system of "outline agreements" with special codes in the SAP financial system. These outline agreements comprise documents in the financial system that specify vendor relationships for the service company and regulated affiliates, and allow authorized internal SAP users to release Contract Release Orders, which act as purchase orders for goods or services from the vendor. The non-utility companies do not use the outline agreement process, but there are also no joint contracts with vendors involving both regulated and non-regulated companies. Beginning in November 2010 the Company introduced a policy to require each regulated operating entity to use individual purchase orders that only allow direct billing for a single company. However, some of the vendors have yet to move to use of a separate purchase order for each company, so that some utility-to-utility convenience payments are still occurring during 2011.

There is evidence that the Company's initiative may have lowered the amounts of convenience payments to some extent. From January through July 2011, the percentage of billed charges from RG&E and NYSEG and from other utilities to the New York companies that were classified as convenience payments dropped from the 2009 and 2010 levels of 49 and 52 percent, respectively, to 26 percent.

Nevertheless, convenience payments remain an issue. There are good reasons why some support from utilities to other affiliates could include payments to vendors, such as contractors, for services rendered as part of the work. There is no reason for those to be excluded from the inter-affiliate bills and there is also no reason for them to be classified as convenience payments.

3. The Company's annual budgeting and service-agreement processes offers sufficient opportunity for NYSEG and RG&E to address the services provided by the service company and other affiliates.

The basic terms of the inter-affiliate service agreements are not normally renegotiated each year. However, there exists a process for planning the extent and nature of the services to be provided through the annual budgeting process. This planning process incorporates both operational and maintenance (O&M) expenses and capital costs. The New York utility President and Vice President, Controller and Treasurer, review and approve all budgets involving the New York utilities. The President signs the service agreements.

Each service company functional-area lead estimates the costs of that area for the service-company-provider agreements. Most cost estimates are based on historical data, although some planned or expected one-time expenses, such as those for special projects, are included.

The utility controllers and presidents estimate the costs for the utility-provided inter-affiliate services. These are based on budgets developed by each operating company cost center. The budgets include an estimate of how much time employees in that center will spend supporting other operating entities. The New York Controller Organization coordinates and validates the New York operating company budget development process. After these budgets are developed, they are rolled up for approval under the coordination of the IUMC Control Group.

The Board approves the budgets when the budgeting process is complete. The service company budget is approved prior to the operating company budgets, usually toward the end of the year. After approval, the IUMC Administration group updates the current service agreements to include a table of estimated costs in the budget by function or cost collector (I/O or WBS) and the cost assignment methods for these costs. The IUMC Legal Department reviews the agreements before they are sent to the operating company presidents and controllers for their review and approval. Once all signatures have been acquired, the original signed service agreements are retained and filed by the IUMC Administration Group and copies are supplied to the receiving and providing Presidents.

IUSA finalizes the annual budgets in the February-to-March time frame, following the annual book close. The IUMC assistant controller then sends the budgets to the operating companies for approval. During the course of the year, the Company makes three revisions to its original budget estimates. The first revision occurs in March, the second in June, and the third in September. The second revision is used to adjust the original inter-affiliate service estimates, and is the only budget revision that affects the estimates in the service agreements. At this point, for example, the service agreements can be updated mid-year to include situations when a client company determines during the year the need for a specific type of service that was not originally included in the budget. If there is a question or issue with the service company's cost estimates, the operating entity president works out the disagreement with IUMC Administration group.

Changes to the service agreements are usually made as part of the budgeting process; however, mid-year changes can be made if an event, such as a merger or divestiture, warrants a change. In practice, however, Liberty found that the wording of the service agreements rarely changes during the year, even with a divestiture. As an example, there appear to have been no changes in the service agreements that account for the changes in the allocators required by the sale of the Southern New England gas companies either during 2010 or between the 2010 and 2011 service agreements. The Company did note that the sale changed the reporting structure for NHG, which caused the need for transactions from the New York companies to NHG and thus for service agreements with NHG, which were added in 2011.

4. The company's processes for monthly review of affiliate transactions offer sufficient opportunity for NYSEG and RG&E to monitor the affiliate-provided service performance.

IUMC holds monthly actual-to-budget variance analysis meetings; they include corporate, service-company, and operating-company personnel, including the operating company controllers. Actual-to-budget data reviews are performed at the company and service-function levels. The timing of the report distribution is the eighth workday of the month-end close process. The reports used during the actual-to-budget variance reviews are by company and department, with month-to-date and year-to-date comparisons of actuals to plan and prior year results. The operating companies are provided a variance report template to fill out and explain variances exceeding 10 percent of budget or $50,000. The operating companies submit the completed template to the planning group in the IUMC Assistant Controller's organization. The planning group then aggregates the data in total and by each operating company. Jurisdictional reports are then created as part of the Performance Management Review (PMR) process.

In addition to these formal review meetings, which occur after the month-end book close, there is a preliminary monthly review of intercompany billings before the final close. A conference call occurs every month between the service company personnel and the affiliates to review actual-to-budget variances and trends. Representatives from IUMC and the affiliates attend the call. Most, if not all, issues are discussed, investigated, and analyzed during the month end close. Answers are to be provided by the tenth work day of the month, before consolidation of the books and final close.

The New York Companies' controller must review and authorize payment for all intercompany invoices. He has indicated that he challenges invoiced items that do not appear appropriate. This provides a control point for the operating companies in assuring appropriate and properly authorized affiliate transactions. The service company personnel manage and review the intercompany activities during the end-of-month closing to ensure the intercompany accounts receivable and payable are reconciled and settlements are applied correctly to the service company's and affiliates' books.

5. The Company's affiliate transaction costing methods meet the requirements of the New York Code of Conduct.

The New York Code of Conduct requires that affiliates provide corporate shared services to NYSEG or RG&E on a fully-loaded cost basis. The Code of Conduct lists corporate governance, administrative, legal, purchasing, insurance and risk management, engineering and construction management, accounting, and information technology as examples of shared services. Other goods and services must be provided to NYSEG or RG&E at the lower of "actual cost" (defined in the Code of Conduct as original cost, net of accumulated depreciation, of the affiliate that first acquired the good of service) or market value. Asset transfers greater than $1 million annually, other than those defined as electric or gas plant, from NYSEG or RG&E to an affiliate must be at the higher of market or net book value (defined in the Code of Conduct as original cost net of accumulated depreciation to the affiliate that first acquired the asset). Additionally, non-utility affiliates must compensate NYSEG and RG&E for services provided to them at tariffed rates or, if the services are not tariffed, at the higher of "fully-loaded cost" or market price.

In practice, the Company considers all utility-provider and service-company-provider services covered by the service agreements to be shared services, which appears to be consistent with the intent of the Code of Conduct. The inter-affiliate billing for these services is at cost. The parent and service company do not charge any management fees to the utilities.

The Company also charges asset and inventory transfers as well as the labor and expenses for loaned employees at cost. All inter-affiliate asset transfers have been less than $1 million annually. Although the service agreements for services to be provided by NYSEG or RG&E to non-utility affiliates, such as Energetix, NYSEG Solutions, and Cayuga Energy, call for the services to be priced "at cost," it appears that NYSEG and RG&E only make convenience payments and provide tariffed services to non-utility affiliates.

IUSA is preparing to use affiliate IEP to provide substantial levels of engineering and construction management work, as detailed further in the preceding chapter. Liberty could not test the compliance of costing of prior IEC/IUSA transactions with applicable requirements, policies, and procedures, because they are only just set to begin. These agreements indicate that the IEP services will be "at cost and below market, which require [IEP] to fairly and equitably charge direct fully-loaded costs for which it renders services to Client Company," and that the "intent" is that charges will be based on fully-loaded costs without including any profit margin. The Company has estimated that IEP's fully-loaded costs are 15 percent below market rates. Note that Recommendation #1 from Chapter Two calls for IUSA to suspend such transactions.

The Company has performed and commissioned relatively few studies of the competitiveness of internally provided services compared to those provided by external suppliers. The Company performs some performance analysis and benchmarking, has commissioned some compensation studies, and has performed project-level studies of insourcing versus outsourcing. The Company also examined the competitiveness of IEP's services versus outside contractors at the time of establishing the service agreements with NYSEG and RG&E. We did not find those comparisons to be determinative, for the reasons detailed in Conclusion #3 of Chapter Two. IUMC also outsources some services provided to its affiliates.

6. **The NYSEG and RG&E affiliate service agreements are adequate in form and content, but include a number of out-of-date elements.** *(Recommendation #2)*

The New York Code of Conduct requires service agreements for affiliate transactions. The NYSEG and RG&E service agreements with their affiliates satisfy the basic requirements of a service agreement. They provide a high-level list of services that is sufficiently comprehensive to cover the actual services provided, include estimates of the costs for providing those services each year, and indicate how the costs for those services will be treated. The New York utilities' president and controller are involved in the annual budget negotiations, and the president must sign the service agreements before they become active.

Aside from the estimated costs of the services to be provided in each year, the service agreements generally do not change from year to year or during a year. Most of the language has remained unchanged since the 2002 time frame, when the Code of Conduct requirements for service agreements were introduced. The Company has purposely made the service descriptions generic and kept the terms of the agreement flexible to allow the companies to provide each other the support required. For example, although the different utilities have their own call centers, the utility-provider service agreements list call-center services. The Company has explained that the call-center services listed in the agreements are intended for emergency support across the utilities, although that point is not clear in the agreements.

The Company believes that the high-level generic descriptions are adequate, and that the listing of services provided has been sufficiently tested and documented in the agreements in order for the basic agreement language to stabilize. Discussions between the provider and client companies is part of the annual budgeting process, and serves the purpose of providing some more specificity and planning for the services to be provided. The annual cost estimates from the budget by function or cost collectors that are attached to the agreements provide some specificity in the services to be provided each year, but these categories are often quite broad. Aside from this, no other documents provide a more specific designation of the services in a given year.

The service agreements specify the methods for assignment and allocation of the service costs. However, many of the allocation methods listed are outdated and obsolete.

The utility-provider service agreements list 14 allocation methods and specify that some of the services provided should be allocated using specific allocators. For example, the "Call Center Ratio" is to be used for call center costs, the "Customer Billing Ratio" for customer billing costs, the "LAN/Wan Service Ratio" for network support costs, the "Communications Ratio" for telephone and voice costs, and the "Customer Billing Ratio" for credit and collection costs. However, in practice, all utility-provider costs are direct charged and not allocated; only service-company costs are allocated. Direct charging is a superior method of cost assignment to allocation when it is at all feasible, but the fact that it is uniformly applied is not documented in the service agreements.

The Company uses only two of the cost-causative allocation types listed in the service-company-provider agreements. Several of the Regulated Global Factors, which allocate costs from the service company to the utilities, have become outdated or inaccurately described in the service agreements with the sale of the Southern Connecticut gas companies. Except for allocations subject to the TSA, these companies have been removed from the allocators in practice, but that change is not reflected in the service agreements.

In the transaction test, Liberty also noted examples of the use of allocators derived from allocators described in the service agreements, but not explicitly described in the agreements. One example of this is the use of a form of the Electric Allocator, which includes only NYSEG and RG&E, excluding CMP. In these cases, Liberty found evidence that the transaction justified the assignment of costs only to NYSEG and RG&E. However, more explicit recognition that such an allocation occurs would be helpful in the cost manual and service agreements.

Using such outdated and obsolete language in the service agreements causes confusion. It also undermines a key purpose of the service agreements, which is to document the affiliate services and how the affiliate costs are treated.

7. NYSEG and RG&E executed service agreements with almost all of the affiliates to which they have provided or from which they have received services during 2009, 2010,

and 2011; however, a small but significant amount of affiliate transactions during 2009 and 2010 were not covered by service agreements. *(Recommendation #3)*

Liberty's analysis indicates that more than 99 percent of the dollar value of costs invoiced between the New York utilities and their affiliates during 2009, 2010, and 2011 was covered by signed service agreements. As a result, the Company has been fairly diligent in assuring service agreements exist before transactions take place.

Liberty found no instances of affiliate transactions without corresponding service agreements during the portion of 2011 reviewed in detail during this audit (January – July 2011). However, \$1.7 million (\$1.0 million, net of convenience payments) was invoiced without service agreements during 2009 and 2010. The majority of those amounts involved transactions with CMP. In both 2009 and 2010, there were transactions from NYSEG and RG&E to CMP but no corresponding service agreements; in 2010, there were transactions from CMP to RG&E but no corresponding service agreement. Most of the remainder of the amounts invoiced without service agreements involved transactions from SCG to NYSEG and RG&E in 2010.

In explanation of these discrepancies, the Company stated:

> *In 2009 and 2010 service agreements were established between NYSEG/RG&E and other affiliates when it was expected that charges would occur between those affiliates. If the budget contemplated affiliate charges then the Company would set up the applicable service agreements at the beginning of the year. IUMC had not anticipated the charges between the affiliates noted in the question…. In all cases, the Companies followed the cost allocation protocols established in the Code of Conduct approved by the NY PSC, which requires that all inter-affiliate costs of this nature are charged on an actual-cost basis.*
>
> *To the extent that the Companies expected continued occurrence of these types of charges, appropriate service agreements have been established for 2011.*

The Company has stated that SAP controls will not allow one entity to bill another entity without a service agreement. Also, if an entity bills for a service that is not included in the service agreement, the system is not supposed to allow this charge. Other quality checks noted by the Company include:

- Required approvals by manager of all time reports
- Specificity of how accounts payable process is handled
- Specificity of the monthly billing to the entities.

The Company has explained that the SAP systematic controls are table driven. A control table checks that transactions contain affiliate code combinations that are valid combinations based on the service agreements. However, the control table does not provide this validation if the transactions involve affiliates not using SAP. Additionally, "When payroll transactions are interrupted, the table edits are lifted in order to prevent delays. Control is reverted back to the supervisor who approves the time and/or the fleet utilization."

Nevertheless, almost all of the amounts invoiced without service agreements in 2009 and 2010 involved CMP or SCG, both of which used the SAP ERP system. Thus, the Company's stated financial controls should have caught these transactions.

8. The Company's inter-affiliate billing and payment process provides an adequate means for NYSEG and RG&E to review and approve the accuracy of the charges for affiliate transactions.

NYSEG and RG&E receive and render invoices for affiliate transactions each month. The service company prepares all NYSEG and RG&E invoices to their affiliates. The invoices are created within the SAP accounting system once the transactions are posted to the general ledger. They contain both the total bill and details of the charges. As of October 2010, all affiliates that use SAP and the non-regulated affiliates began receiving bills itemized at the I/O level.

After the system generates the invoices, the Company provides various means for review and approval to assure accuracy of the charges. The IUMC assistant controller's group initially reviews the invoices for accuracy, examining anomalies and trends and reconciling of cost charges and allocations between the bills and the accounting system. The New York companies' controller receives the statements via e-mail along with supporting documentation, and must approve the bills before they are sent to the New York company president for final approval and payment through a check request to the corporate Treasury Department.

The Company has indicated that most billing discrepancies are addressed during the monthly actual-to-budget variance analysis and review meetings, which occur before the actual billing statements are sent to the affiliates. At this point, the New York controller and the other affiliate controllers have reviewed the client billings and approved the billings for payment. The IUMC assistant controller's group has indicated that it receives questions from the controllers on about one-half of the service company invoices sent. A change is required about once a year at most. If there is a need to make an adjustment to the invoices, adjustments will be made in the following month's closing process.

NYSEG, RG&E, and other companies pay the total bill; there is no netting of intercompany balances. The Company has stated that it has adopted this approach to help provide transparency for the intercompany charges.

9. A significant percentage of the payments for inter-affiliate transactions between NYSEG and RG&E and their affiliates have not been made or received in a timely fashion. *(Recommendation #4)*

The service agreements and the Company's cost manual allow 30 days for payment of the inter-affiliate invoices. Although the service agreements state that there will be 0.5 percent late payment fee for every month there is an outstanding balance, the Company has stated that the late payment fees are not actually charged.

Liberty observed the following amounts of late paid charges during 2009 and 2010:

Late Inter-affiliate Payments during 2009 and 2010 (in Thousands)				
	To NYSEG	**From NYSEG**	**To RG&E**	**From RG&E**
Total Invoiced	138,245	36,595	86,925	38,277
Total Late Paid	15,025	11,074	24,450	7,867
Percent Late	10.9%	30.3%	28.1%	20.6%

Overall 123 invoices were paid after the 30-day interval allowed in the service agreements. In total, 20 percent of all the invoiced amounts (both those from NYSEG or RG&E and those to the New York companies) were paid late. An even larger fraction, 25 percent, of the amounts invoiced from NYSEG and RG&E to their affiliates was late. Approximately half of the late invoices were paid between 30 and 40 days after the invoice date and three-quarters within 50 days. However, 11 percent of the late invoices were paid more than 100 days after the initial invoice date; three invoices were paid more than 450 days after the invoice date.

In response to an inquiry about this situation, the company replied:

> *Because the invoicing processing often time includes some questions and answering processes between the companies we as an organization try to be flexible with considering invoices paid late. We want to ensure that the correct amount of review has been completed and that both parties are comfortable with the invoices.*

The Company also confirmed that there have been no late fees charged as a result of this review process. While extra time for answering questions might explain those bills that were paid 10 or even 20 days after the 30-day standard payment period, this explanation is difficult to credit for explaining the 10 percent of the late invoices that remain unpaid more than 100 days after the invoice date. Indeed, the Company has also stated that the affiliates rarely dispute the billed charges at the time they are billed. The lateness of inter-affiliate invoice approval and payment may indicate that the Company has insufficient resources devoted to the process of review and reconciliation of inter-affiliate charged. At the very least, it calls into question how seriously the Company is taking this process.

10. The Company's cost-assignment methods are adequate to provide accurate and comprehensive cost assignment of common costs to affiliates, and are consistent with the New York Code of Conduct requirements.

The Company's methods are consistent with the requirements of the Code of Conduct and the specific methods designed to implement the Code of Conduct described in the Company's Cost Manual and inter-affiliate service agreements. The Company uses the SAP system to make the assignments of the inter-affiliate costs, basing the assignment on the SAP accounting code structure, specifically the use of the I/O and WBS project codes. These project codes or "cost collectors" in combination with the sending and receiving codes provide the mechanism for determining the cost assignment, whether and to which company the cost will be directly assigned or whether and how the cost will be allocated. These project codes are associated with the records in the financial system and allow assigned and allocated costs to be traceable and transparent.

Each cost collector has an associated direct assignment or allocator. Labor, invoices, and journal entries are processed during the month-end close. At that time, the transactions and their associated costs along with overheads are direct charged or allocated to affiliates. Two processes are used to assign and allocate the overheads. One process allocates the benefits and other labor overheads, which follow direct labor (including both productive and non-productive time) and another process allocates other overheads (such as, fleet, stores, and building occupancy). The service company personnel manage and review the inter-company activities during the month-end close to ensure the inter-company accounts receivables and payables are reconciled and settlements are applied correctly to the service company's and affiliates' books.

All the I/O and WBS codes with operating companies as service providers to other affiliates lead to direct charging of costs to other affiliates. Those associated with the service company as service providers either direct charge or allocate costs to affiliates. Some costs are assigned or allocated to the U.S. holding company (IUSA). Costs directly attributed to the holding company and those allocated by the service company to the holding company remain on the holding company's books and are not re-allocated to the affiliates. The types of costs included at the holding company are strategic planning and governance costs such as corporate tax payments, depreciation, and interest for IUMC debt. Tax payments are made by the holding company and then charged through IUMC to the operating companies as part of the settlement process, setting up the tax liability on the operating companies' books.

NYSEG and RG&E file annual Code of Conduct reports with the Commission. In compliance with the Code of Conduct requirements, these reports summarize the asset transfers, employee transfers, employee loans, cost allocations, affiliate transactions, and competitor or customer complaints related to conduct between the New York Utilities and affiliates during the past year.

11. **The Company's cost manual and service agreements document at a high level the methods used to allocate and assign inter-affiliate costs to NYSEG and RG&E; however, some of the details of the documentation are no longer applicable or necessary and there appears to be limited documentation of the detailed cost allocation procedures.** *(Recommendation # 2)*

The cost manual, which NYSEG and RG&E file annually with the Commission as part of the annual Code of Conduct reports, contains a high-level description of the cost allocation and assignment methods used by IUMC. The IUMC service agreements incorporate the language of the cost manual. The utility-provider service agreements provide a high-level description of the methods used for assigning costs of operating-company-provided inter-affiliate services.

The cost manual and both the service-company-provider and utility-provider service agreements specify three cost assignment and allocation approaches that will be used:

- Direct charge costs "whenever feasible"
- Allocate "directly attributable costs" based on a cost-causal relationship (*e.g.*, payroll costs allocated based on number of employees)
- Allocate "indirectly attributable costs that are common to all" client companies using the global allocation factor, which takes into consideration the relative size of each client company based on gross revenues, gross payroll expense and plant.

Costs “that can be directly attributed to direct charges,” *i.e.*, Administrative and General (A&G) overhead, are to be allocated in proportion to the direct charges or other appropriate cost allocations. The service agreements with IUMC as service provider note that A&G costs not associated with a specific, identifiable, causal relationship are pooled and allocated to all system companies, including the holding company. The service agreements also list and define allocators to be used for cost allocation.

However, as noted in Conclusion #6, the cost manuals and the IUMC-provider service agreements contain obsolete cost allocation methods and outdated descriptions of some of the cost allocators, and the utility-provider agreements indicate that some of the costs will be allocated although the Company actually direct charges these costs. Additionally, although the cost manuals and service agreements refer to the use of internal orders for accumulating the costs, there does not appear to be any detailed description either in these documents or elsewhere of how the cost collectors are used within the SAP coding and month-end book-close process.

The service agreements also do not explicitly address the transfer of intellectual property and other intangible benefits among the affiliates. The New York Code of Conduct does not address specifically the transfers of such items, but does contain restrictions on providing customer and marketing information and employees to certain unregulated affiliates. IUSA has indicated that it considers compensation for intellectual property transfers to be covered by the general statement in the service agreements that services will be provided at cost. However, neither the services listed nor any other provisions in the service agreements explicitly describe intellectual property transfers. Similarly, the Code of Conduct for IUSA employees addresses the protection of intellectual property, but not the transfer of intellectual property among affiliates. Other holding companies that Liberty has examined do specifically address the transfer of intellectual property, trade secrets, and other intangible benefits among affiliates in their service agreements, cost manuals, or codes of conduct. We consider this approach to reflect best practice.

12. **IUMC has adequate systemic and procedural controls in the accounting and cost assignment process to prevent affiliate cross-subsidization, but they do not appear to be consistently applied.** *(Recommendations #3 and #5)*

The service company and affiliates are structurally separate; each company has its own chart of accounts and general ledger. The Company has implemented system and manual procedures to ensure that affiliate transactions are recorded and invoiced appropriately. The SAP system code contains table-driven edits and validations that are applied to inter-affiliate transactions. These controls, which do not appear to be documented, prevent charging goods and services between affiliates unless the appropriate project and Company codes are used and these codes are appropriate for the sending and receiving cost centers. The Company also has documented processes to comply with Sarbanes-Oxley requirements. These include financial and accounting processes that affect cost assignment.

Employees are assigned to home cost centers in SAP, which identifies the company (company code) and department (cost center) to which each employee is assigned. The SAP internal orders are unique to each home cost center, and are based on the scope of work performed. Employees typically charge all of their time to the internal orders associated with their home cost center. When employees perform work outside of their home cost center, SAP table-driven validations prohibit employees from charging their time to internal orders which belong to the other companies. If employees attempt to enter their time in SAP using an inappropriate internal order, they receive an error message and their time entry is not accepted. This validation also applies to convenience payments. Exceptions are made on a case-by-case basis when there is a valid business need for an employee to charge time to another company. These validations do not apply to work between NYSEG and RG&E, because such a large number of employees in these companies perform work for both companies.

All charges between companies are subject to a manual billing and approval process. At the end of each month IUMC Administration downloads all intercompany charges from SAP and prepares individual invoices that include summaries of charges by employee and internal order. The invoices are forwarded to the appropriate authority at the company receiving the charges for review and approval prior to the transfer of funds. At this time the approving authority has the opportunity to ask for additional details or dispute charges. If a charge is in question, IUMC Administration contacts the employee who originated the charge and requests additional information. If it is determined the employee's time was not entered appropriately, the employee is instructed to re-enter the time using the appropriate internal order or submit a correcting journal entry for convenience payments.

The Company uses controls to ensure that services ordered from vendors are actually received. All purchase orders require a receipt in order to place the expense on the books as a receivable. A validation is performed to ensure that the accounting information on the receipt matches the accounting information on the purchase order. The Company also implemented in November 2010 a new vendor invoicing process for services (*e.g.*, consultants) and non-stock material purchases (*e.g.*, office supplies) to provide increased control and accountability. This process requires vendors to provide invoices to a single company only, rather than multi-company invoices or invoices to a single company for services rendered to multiple companies. This new process helps to reduce the need for convenience payments.

Each employee's supervisor reviews and approves the time and expense reports and the assignment to the cost collectors that are used for cost allocation in these reports. If an employee did not properly code the time sheet or expense report, or did not submit a time sheet, the supervisor of the employee is notified by human resource personnel. The time sheet is re-entered in the system with the corrected information. The Company has noted its policy to direct charge as much as possible as another control. The labor costs of loaned employees are direct charged to the company and department that request the employees. Each affiliate company receives a monthly invoice prepared by IUMC containing a detailed listing of all cross-charged labor by employee. The invoice is itemized such that direct charges, overheads and shared services costs are shown separately by work request. The requesting company approves the charges to be incurred before the labor is cross-charged from the originating company to the receiving company. The funds are not moved until the receiving company controller approves the billing of the labor cross charges. Additionally, both the service company and utilities review all cross-charges twice a year during the service agreement process.

However, as noted in other conclusions, some of these controls do not appear to have been consistently applied or can be readily bypassed. For example, the Company has indicated that edits validate that inter-affiliate services charged and billed are covered by service agreements, although, as noted in Conclusion #7, this control has been inconsistently applied. The Company has noted its stated policy to prefer direct charging; however, the amount of actual direct charging has been relatively small, aside from the operating companies, where it is required, as noted in Conclusion #14. Additionally, although there are formal training documents for time reporting, the Company does not have employee guidelines or policy statements that would help determine when a transaction should be direct charged or allocated, as noted in Conclusion #13. The Company relies on scrutiny and reinforcement from the supervisors to enforce the policy of preferring direct charging. This has not always sufficed to prevent cases of employees charging time in ways that do not comply with the service agreements, as noted in Conclusion #19.

13. **The Company has limited training or a comprehensive policy document to provide guidance to employees in the appropriate assignment of affiliate transaction costs.** *(Recommendation #5)*

The Company maintains adequate training and documentation for using the time-entry system to enter time; however, there are limited guidelines to help employees determine how to appropriately assign the labor costs, including when a transaction should be direct charged or allocated. Supervisors review and approve the employees’ time and expense reporting based on the functions they perform and provide the necessary training and guidance to employees when required. The Company relies on supervisors to reinforce the importance of direct charging of time and expense and to inform employees of new accounting codes that should be used for time reporting purposes. The Company has stated:

> *There are no separate written guidelines, policies, or procedures related to time reporting. Key controls related to the time reporting process are documented in the company’s internal guidance utilized by its internal auditors during their review of the time reporting process.*

The Company’s service agreements also specify that direct charging of costs should be given first priority. The relatively small percentage of IUMC time charged directly suggests that the statements in the service agreements about the need for direct charging are insufficiently stressed in time reporting and may indicate the need for the Company to develop a time-reporting policy document and share with employees through training and review with managers.

The IUSA Code of Conduct, which is issued to employees, contains a brief section entitled “Affiliate Rules and Transactions” that provides some guidance on affiliate transactions. However, the statements are fairly general:

> *Transactions between a regulated utility and Iberdrola USA or its other regulated or non-regulated affiliates may be subject to sets of standards issued by the individual state commissions governing the regulated utility. In addition, these transactions may also be subject to rules set forth by the FERC. Employees will comply with all statutes, regulatory rules and orders, and accounting standards as they apply to transactions between affiliates. Affiliate transactions involve the provision, sale, assignment, transfer or lease of goods, services or other assets between a regulated utility and Iberdrola USA or its other affiliates. These*

standards and cost allocation requirements are referred to as affiliate rules. They were issued to ensure that transactions between a regulated utility and Iberdrola USA or its affiliates are appropriate. They protect against the regulated utility showing favoritism toward its affiliates, sharing certain information with affiliates or applying inappropriate affiliates' costs to the regulated utility. You should consult your supervisor, subsidiary Compliance Officer or Iberdrola USA's Compliance Officer, as well as your subsidiary affiliate rules for guidance on how they apply to your particular situation.

Furthermore, although the New York Code of Conduct contains rules governing transactions between NYSEG or RG&E and unregulated affiliates, the Company's internal Code of Conduct includes a statement that contradicts the existence of such requirements:

Q: Do these affiliate rules apply to transactions between unregulated affiliates?

A: No. The affiliate rules apply only to transactions: (i) between regulated utilities; (ii) between a regulated utility and Iberdrola USA; (iii) between a regulated utility and Iberdrola USA Management Corporation; and (iv) between Iberdrola USA or Iberdrola USA Management Corporation and other regulated or non-regulated affiliates.

14. The Company's stated cost assignment policy is to give first preference to directly assigning costs and next to use a cost-causative method to allocate costs; however, IUMC directly assigns a relatively small proportion of costs to affiliates. Most of the remaining costs are allocated using general rather than cost-causative allocation. *(Recommendation #5)*

Direct assignment offers a much better approach than using allocation factors to attribute the costs of inter-affiliate transactions. Inappropriate allocations can lead to cross-subsidization among affiliates. Direct assignment can also help an operating company manage and contain affiliate transaction costs more precisely, leading to potential overall cost savings.

The current IUSA cost assignment policy is to give priority to direct assignment. Only the service company can assign costs to affiliates using allocation factors; inter-affiliate costs originating in an operating company are direct charged. These procedures help to increase the direct charging of the overall inter-affiliate costs. However, most inter-affiliate costs originate in the service company. Only 25 percent of the service company costs assigned to the New York utilities during the period from January 2009 through June 2011 was direct charged. The following table shows the IUMC cost assignments from 2009 through July 2011 by assignment type:

Service Company Charges by Cost Assignment Method (in Thousands)								
Cost Assignment Method	***2009***				***2010***			
	RG&E	***NYSEG***	***Total***	***Percent***	***RG&E***	***NYSEG***	***Total***	***Percent***
Direct	$10,930	$12,418	$23,348	28.7%	$5,491	$10,880	$16,371	23.5%
Allocated	$19,347	$38,583	$57,930	71.3%	$18,121	$35,238	$53,359	76.5%
General Allocator	$16,330	$32,784	$49,114	60.4%	$15,725	$32,502	$48,227	69.2%
Global	$6,086	$9,415	$15,500	19.1%	$3,932	$5,552	$9,485	13.6%
Regulated Only	$10,244	$23,370	$33,614	41.4%	$11,793	$26,950	$38,742	55.6%
Cost-Causative	$3,017	$5,798	$8,816	10.8%	$2,396	$2,737	$5,132	7.4%
Total	$30,278	$51,000	$81,278		$23,612	$46,118	$69,731	
Cost Assignment Method	***Jan. - July 2011***				***Jan. 2009 - July 2011***			
	RG&E	***NYSEG***	***Total***	***Percent***	***RG&E***	***NYSEG***	***Total***	***Percent***
Direct	$2,647	$5,185	$7,832	21.9%	$19,069	$28,483	$47,551	25.5%
Allocated	$9,537	$18,414	$27,951	78.1%	$47,005	$92,235	$139,240	74.5%
General Allocator	$8,433	$16,683	$25,116	70.2%	$40,488	$81,969	$122,457	65.6%
Global	$2,062	$3,794	$5,856	16.4%	$12,080	$18,761	$30,841	16.5%
Regulated Only	$6,371	$12,889	$19,260	53.8%	$28,408	$63,208	$91,616	49.0%
Cost-Causative	$1,104	$1,731	$2,835	7.9%	$6,517	$10,266	$16,783	9.0%
Total	$12,184	$23,599	$35,783		$66,074	$120,718	$186,792	

Liberty has found that other U.S. utilities have been able to directly charge as much as half or more of the service company's costs. Increasing the direct charge percentage of service-company charges to the New York utilities to 50 percent would have increased the directly charged costs by $32 million for NYSEG and $14 million for RG&E for the period from January 2009 through June 2011. However, comparisons with other utilities are difficult, because the particular functions performed at the service companies differ among public utility holding companies. There are few alternatives to using allocation factors to assign many common governance functions. If a service company is largely devoted solely to such functions, the proportion of direct charging will tend to be less.

Liberty examined the total costs that are currently allocated to the New York utilities originating in the nine cost centers (Business Transformation, Office of the COO, Electric T&D, Gas Operations, Customer Service, Asset Management & Planning, Public Affairs, Information Technology, and Internal Audit) that are coded in the financial system with the same names as those from which the operating companies currently directly assign costs to each other and the service company. The functions of these operating company cost centers and the equivalent ones at IUMC are likely to be very similar; therefore, the fact that the operating companies are able to directly assign all the inter-affiliate costs suggests that IUMC may be able to achieve greater direct charging of the costs from these cost centers as well. Costs from these cost centers represent 9 percent for NYSEG and 12 percent for RG&E of the total allocated service company costs from January 2009 through June 2011, or $10.9 million for NYSEG and $7.7 million for RG&E.

These numbers are presented merely as illustrations of the amount of dollars at stake. Liberty recognizes that it is not likely that all the costs in the selected cost centers can be directly assigned. On the other hand, other service company cost centers might also be able to increase the amount of direct charging. For example, Liberty did not include in this analysis cost centers with similar but not identical names, which could be a source of additional direct assignment. Furthermore, even if all these costs were directly assigned there is no guarantee that the overall costs attributed to the New York utilities will decrease. They could, in fact, increase, since cost attribution merely shifts costs among the affiliates. However, even if this should be the case, increased direct cost assignment provides greater transparency and allows the New York utilities to better analyze and question the costs with the potential of eliminating or reducing unnecessary costs.

Liberty also notes that the vast majority (approximately 95 percent) of the service company's allocated costs are allocated using the Massachusetts Formula, which is a broad-based or general allocator, based on the average of gross plant, payroll, and revenues. The small residual amount of allocated costs use "cost-causative" allocators, or those based on quantities more directly related to the functions performed, such as employees for human resources costs, thereby providing a more precise allocation of costs than general allocators.

The Company has stated that its predominant use of the general allocator versus more cost causative factors is to maintain consistency of allocated costs from year to year. The Company believes that its general allocators cover the key areas that affect the business and include all the factors that would be considered in the separate cost causative factors and that sufficient specificity is attained through the variation in the specific companies included in the various Massachusetts Formula allocators. The goal is to keep the allocation process as simple as possible, using as few allocators as possible. Liberty's review of the allocation factors currently used indicates that the allocation amounts would not vary significantly if the existing cost-causative allocators were used more extensively.

15. IUMC has an adequate cost-assignment review process.

During 2010, the Company implemented a new data review and approval process during the month-end closing process. The IUMC Assistant Controller and his staff review and approve charges and credits related to accounts-payable transactions (purchase orders, invoices, check requests, *etc*.). Operating company personnel review intercompany transactions affecting their operating company at the same time. Variance reports are used during the close process to determine if trends are consistent with prior periods and identify any anomalies during the month, which are then investigated. Based on the results of the review and approval process, issues are identified and a determination of the disposition is made. For example, if there is an error in an invoice, the adjustment will be made during the month-end process. If an error is found in an invoice or in time entry, the associated expense is not billed to the operating companies until it is corrected. Once the data has been reviewed and adjustments made to the accounts, the data from each data base is sent to the business warehouse repository where standard reports are produced and ad hoc reporting can be done. At this point, the month-end close and posting data to the general ledgers is complete.

There is also an annual review of the basis data used in developing the cost allocation factors. The IUMC Administration group, which develops the cost allocation factors, reviews the data for trends to identify any anomalies that may need to be addressed. The Company has indicated that the basis data has been fairly consistent within the audit period, as there have not been new major system enhancements or other changes aside from the sale of companies.

16. IUMC's allocation factor calculations are generally accurate and sufficiently documented.

IUMC calculates the allocation factors annually based on the prior year financial statements in February or March each year and loads them into SAP in the same period. Most of the basis data for the allocation factor calculations comes from the SAP financial system, although the Human Resources department provides the employee data. After collecting the basis data, the IUMC Administration group reviews it for trends and year-to-year consistency. The Company has indicated that the basis data has been fairly consistent during the audit period, with the only major changes coming from sales of companies. The allocation factors generally do not change during the year, unless there are significant changes, such as sales of companies.

Liberty obtained the basis data used to calculate all the allocation factors the Company used during 2009, 2010, and 2011, including both the general (Massachusetts Formula) and cost-causative allocation factors. Liberty found the documentation of the calculations sufficient, and was able to replicate the calculations. Liberty replicated the calculations and, with one exception, found them to be calculated properly and in compliance with the service agreements and the cost manual.

The one exception was the Gas Supply Factors for 2011. Liberty found that the Company had used the total electric and gas supply costs for the calculation rather than the gas supply costs only, as required in the definition of the allocator, which caused the allocation percentages for NYSEG and RG&E to be significantly larger than they should have been, because the only other company in the allocator is MNG. However, the total amount of IUMC costs allocated through this allocator from January through July 2011 was less than $1,000. Thus, the error had an immaterial effect for the period Liberty analyzed quantitatively in this audit.

17. IUMC's overhead and clearing account processes are adequate; overhead calculations are appropriate and accurate.

The Company uses clearing accounts as part of the overhead allocation process. Each month, any remaining balances not cleared from the overhead cost pools are moved to the clearing accounts for monitoring purposes. If the amounts in the clearing accounts become too large, the Company may make an adjustment to clear additional amounts in order to minimize large adjustments at year end. The service company allocates overhead costs to affiliates based on standard rates.

The Company uses two overhead categories: a) standard overheads, and b) capitalized overheads. The standard overheads are:

- Benefits
- Stores
- Transportation (Vehicles/Fleet)
- Building occupancy.

The capitalized overheads, which are bucketed by line of business (electric, gas, etc.) to avoid cross subsidization, are:

- Preliminary engineering
- General construction.

The Company monitors the activity in each of these clearing accounts monthly to determine the remaining over- or under-balances that were not allocated at the end of the month. Any balances remaining in the cost pools that have not been allocated are transferred to a specific general ledger clearing account for monitoring. Manual adjustments may be made to the clearing account to re-allocate the costs. The Company uses the forecast as the control and benchmark for the overhead costs. The amounts cleared from the clearing accounts are charged to the appropriate internal control code.

Benefit costs are allocated based on direct labor and include pension costs (capital and expense), Other Post-Employment Benefits (OPEBs), social security taxes, and other benefits such as 401k, dental, and medical costs. The Company defines direct labor to include all payroll time entry, which includes productive and non-productive labor. The pension costs are based on actuarial estimates and managed on an annual basis. The benefits standard rate is applied to all the cost collectors (pools) that capture labor types (straight time, overtime, for example). Prior to 2010, all benefits were found in the same clearing account. Since 2010, they have been broken down into four categories: pension, OPEBs, social security, and all other. The payroll taxes follow direct labor as with other benefits, but for FERC accounting in New York they are placed in the “Other” category. Each category is treated the same, but the Company records them separately.

Stores expense represents the cost of managing the inventory, and consists of warehouse and inventory management functions that are related to the receiving, storage, and issuance of materials. The stores expense is allocated based on a standard rate and applied to all material usage and inventory transfers, materials moved between entities, on a monthly basis. The costs are allocated at the activity code level.

Transportation/Vehicle (Fleet) costs consists of vehicle maintenance costs, including parts, materials (the most significant of which is fuel), and depreciation expense. The costs are charged to a cost collector on the operating companies’ books to develop the vehicle standard rate. The operating companies are assigned vehicles and each vehicle is assigned its own vehicle standard rate. Each company owns the vehicles assigned to them, which allows the companies to manage their own vehicle costs. The overhead cost is based on vehicle usage. Each vehicle is assigned a number and when employees use vehicles they enter the vehicle numbers on their time reports. The cost then follows the use of the vehicle as recorded on the time sheet based on the hours of use and the hourly rate assigned to each vehicle. This rate is based on a five-year history of maintenance costs. The expenses associated with this pool are managed by the operating companies. The “consumption charge” is moved from the pool to the entity that owns the vehicle. All the vehicles are on the utility’s books. If there are any changes to the overhead rates due to a change in vehicle ownership or significant cost fluctuations, the operating companies are notified. In the 2003 to 2005 period, the Company experienced a number of month-to-month rate changes, but the process has been improved since then and rate variation is much smoother now.

The preliminary engineering overhead is used to allocate costs that are for minor construction projects and work not related to a specific project. The costs to be allocated are charged by engineers that design and plan for minor construction projects. These costs are captured in their respective cost pools and include the engineers' loaded labor costs. The standard rate is calculated and the costs are allocated to all the minor gas, electric and transmission construction jobs.

The general construction overhead is used to allocate supervisors' costs for the minor construction projects. The methods used to calculate the standard rate and allocation of these costs is the same as the preliminary engineering overhead. The costs to be allocated are charged by the employee supervising the many small projects. These costs are charged to the appropriate cost pools and allocated to the construction projects by applying the standard overhead rate.

The occupancy and asset usage overhead is used to allocate the building and equipment costs of employees charging their time to the affiliate companies. The building costs are allocated based a square footage component. The asset costs include property taxes, depreciation and other asset-related costs that are charged to the appropriate cost pool. Once the standard rate is developed, the rate is applied to the direct labor of the employees using the assets.

Liberty reviewed transactions with allocated and directly assigned overhead costs as part of the transaction test and found the calculations to be accurate.

18. There exist sufficient means for employees to properly assign their time to codes that allow appropriate direct charging and allocation for affiliate transactions.

Most employees use the self-service time reporting module (ESS) in SAP for time entry. Liberty witnessed a demonstration of the time-entry system and found the system to be straightforward and easy to use. Employees enter cost object codes to indicate whether the time was regular time worked, one of three categories of overtime, or one of various categories of non-worked time (sick time, holidays, vacations). Employees can split their time during the day between different cost objects representing productive and non-productive time; for example, they can record portions of the day to sick time. For time worked, employees must enter "cost objects" or "cost collector" codes (Internal Orders or, for capital projects, WBS codes), which the system uses to determine the cost assignment. For IUMC employees these codes determine whether an affiliate will be directly charged for the time worked or the specific allocator used to allocate the charge to several affiliates. Although the time reporting system does not automatically limit the fractions of hours reported, the Company requires employees to report time in no smaller than quarter-hour increments. The system has drop-down menus to provide the options available to the employees and assist the time entry. The system also allows employees to save "work lists," which store the accounting codes that each employee normally uses for time reporting. Timekeepers located in all the affiliates perform timekeeping for bargaining unit employees at NYSEG and RG&E and other employees without computer access.

19. The Company's time reporting system and processes contain controls to assure accurate time reporting and appropriate assignment of labor costs, but these controls have not always sufficed to prevent errors. *(Recommendation #5)*

High-level checks in the time entry system reject time reports with obvious errors. However, the Company relies primarily on the manager review and approval process for catching time reporting errors. The Administration Group in the IUMC Assistant Controller's organization, the Controller, and the departments that ultimately receive the charges also review the time reports. SAP provides variance reports that are used to help identify time reporting errors. SAP has the ability to provide lower-level edit checks of the time reports, but the Company has chosen not to use these features of the system, because of the need for flexibility during unusual time reporting situations, such as storm events.

When an employee fails to complete a time report before the payroll cycle, or the employee's supervisor did not approve the report, the Payroll group still processes a check or electronic funds transfer for that employee using the default number of hours for the pay period. When this occurs, the employee's supervisor receives a notice of the problem, and the employee is requested to enter the time and have it approved. The cost assignment of the employee's time is then corrected with the next pay cycle. The approval authorities are linked to the organization charts that reside in SAP.

Supervisors and managers are required to approve all timesheets. If the supervisor or manager is unavailable to approve time for direct reports, the next-level manager approves the timesheets. If that manager is not available, Payroll approves the timesheet and sends an e-mail to the supervisor or manager notifying them of the approval. The supervisor or manager is then required to review the time approved for the employee to ensure accuracy and respond to Payroll via e-mail indicating that the time was reviewed and verified for accuracy or that the supervisor requested the employee make any necessary corrections. Time entered and approved through the time-entry system is electronically stored in SAP and retained in accordance with the Company's Records Retention Policy.

In cases where a manager rejects a time sheet, the employee receives a system-generated e-mail notification of the rejection. This notification contains a brief explanation of why the time sheet was rejected. The employee must then fix the problem and resubmit the time sheet for approval. Once a time sheet has been approved, it cannot be changed by the employee. If a change needs to be made, the approval must be reversed and the process starts all over again. The manager's approval module, MSS, allows a manager to approve each line of the time sheet or approve all entries at once. The Payroll group in Human Resources performs a final review of approved time entry before the payroll run. If there are obvious errors, Payroll can reject the time entries and have the manager fix them.

There have been some lapses in the Company's application of the controls. An internal company audit completed in May 2011 noted that the IUSA CEO's administrative assistant was charging time solely to the global allocator, although the service agreements require that the wages of administrative assistants be charged in proportion to allocation of the employees they assist, and recommended reinforcing the required policy with all IUMC administrative assistants. The Company did so late in May 2011. Liberty reviewed a June 2011 transaction as part of the transaction test. This transaction included direct charging by CEO administrative assistants, indicating that the reinforcement appears to have brought the appropriate result. However, this case illustrates that the Company needs to be more diligent in applying the time-reporting, including providing more training and documentation to employees and supervisors on appropriate cost assignment for labor costs.

20. The Company requires positive time reporting, which helps to assure proper cost assignment by placing the decisions at the level at which knowledge of the specific work performed is the most accurate.

The Company's time-entry system requires the employees to enter appropriate cost collectors for each regular worked time entry. That is, the Company requires positive time reporting; the time does not default to a standard cost assignment or allocation code. This positive time reporting is achieved without a significant burden on the employees, through the use of the work lists that allow the employees to easily retrieve and enter the financial codes the employees typically use.

Hourly employees (non-exempt) employees must report time to be paid. Although exempt (bi-weekly) employees are paid if they fail to complete a time sheet before the paycheck is issued for a pay cycle, they must positively record their time beforehand in order for the time to be assigned to the cost objects (I/O or WBS) or non-worked-time codes (vacation, sick time, holidays), and hence to be assigned or allocated to affiliates. Such time entries are typically corrected in the next pay cycle.

Positive time reporting allows more precision and accuracy in time reporting by placing the choice of coding at a level closest to the actual work performed, the employee or time keeper, rather than relying on a larger work center to determine an "average" cost assignment for all employees in the center over time, as a default reporting structure does. Whether a company actually takes appropriate advantage of this capability to be more precise and accurate in the time reporting depends on the actual policies the company adopts for employees to use in time reporting. The fact that most of the IUMC time is charged through general allocators suggests that IUSA has not taken full advantage of the capabilities available.

21. The Company provides adequate documentation and training in the use of its time reporting system and processes.

Employees typically receive guidance from their immediate supervisor as to the appropriate codes that should be used for charging their time. The SAP system contains self-help tools. The Company also maintains training documentation, which Liberty reviewed and found to be comprehensive and easy to understand. This training material is available on the Company's intranet site, which employees can reference for time reporting questions. The Human Resources Service Center is responsible for maintaining the time reporting training documentation. If a time reporting question cannot be resolved by the supervisor or the available on-line tools, the question is referred to a group in the IUMC Assistant Controller's organization.

22. The Company's employee expense reporting process provides adequate means for employees to properly record and assign their expenses.

The Company provides three methods for employees to charge expenses:

- A company-issued credit card
- Reimbursement of out-of-pocket expenses incurred without using the Company credit card through a check request by the employee

- Personal automobile mileage and per diem for travel entered through the time-entry system and reimbursed through the employee's regular paycheck.

With the exception of mileage and per diem, expense reporting is a manual process. Nevertheless, the Company's processes appear to provide an adequate means for accurate expense recording.

The Company encourages employees to charge most expenses to the corporate credit card, which the Company pays directly to the credit card company. The employee receives a statement from the credit card company and must complete a paper log documenting the purpose of the expense and submit all required receipts with this log.

Employees use two different paper forms for reimbursement out-of-pocket expenses: "Business Travel Reimbursement" and "Non-travel Reimbursement." An example of a non-travel reimbursement is the NYSEG-allowed safety shoe reimbursement. The employees fill out and sign these forms, explaining the reason for each cost shown, providing the appropriate accounting information, and attaching any receipts that support the expenses. An employee's manager (or higher-level manager based on approval authority) reviews and approves or rejects the request. The Accounts Payable group conducts additional reviews of all reimbursement forms, including receipt-to-expense validations. Accounts Payable enters the request into SAP, where system edits validate the accounting codes used. The employee is reimbursed by payroll as a "non-standard" payment separate from the employee's normal paycheck. Both the business travel reimbursement forms and the non-travel reimbursement forms and associated receipts are "attached" in SAP to the transaction (*i.e.*, the forms are scanned in as they would be for a paper invoice from a vendor). The paper copies are also archived through Iron Mountain.

23. The Company's employee expense reporting process includes sufficient controls to assure accurate and appropriate assignment of employee expenses.

The employee's manager is responsible for reviewing and approving the expense log. The review includes a check of the receipts against the expenses incurred and verification that all the proper accounting was used. The card expenses are initially default allocated based on the employee's home cost center accounting. The employee receives an e-mail reminder to "reallocate" the expense charges if necessary. After the manager approves the expense log, it is forwarded to Accounts Payable, which conducts a second round of validations. The Accounts Payable group also updates the books, if necessary, when different (non-default) accounting was used for any of the expenses on the log. All the paper log sheets are archived through Iron Mountain for seven years; there are no electronic scans of the log sheets into the SAP system. If necessary, the Company can obtain electronic data on expenses from the credit card company.

24. The Company provides adequate documentation for its employee reporting process.

NYSEG and RG&E maintain employee expense policy and procedures documents, individualized for each company. The IUMC Assistant Controller's organization is responsible for maintaining the expense policy documentation. The Human Resources organization is responsible for maintaining the corporate credit card policy documentation. Liberty reviewed this documentation and found it to be easy to understand and comprehensive.

25. The Company has an adequate expatriate assignment policy and process.

Until the middle of 2011, the Company had a few ad-hoc internal documents describing the policies and procedures for the International Mobility program, but no comprehensive and documented policy and procedures. In response to an internal audit finding, the Company drafted a policy and procedures document for the program, dated July 22, 2011. The procedures include:

- Terms and conditions of the assignments
- Process for initiating the assignment
- Treatment of compensation and benefits
- Relocation process and treatment of relocation expenses
- Housing policy in the host country
- Treatment of expenses during the assignment
- Special allowances and payments provided, such as cost-of-living adjustments, foreign service premiums, vehicles in the host country, education allowances and other family assistance, and payment for emergency and annual vacation trips to the home country.

The International Mobility policies and procedures include conditions to charge the normal labor costs and related overheads to the host company but separate the special expenses associated with the program from the books of the host company. In particular,

- Base pay for a Standard International Assignment is paid by the home company and billed annually to the host company.
- Benefits for a Standard International Assignment are paid directly by the host company.
- Compensation for Graduate Program participants is paid directly by the host company, since these expatriates are officially employees of the host company during the assignment.
- Special allowances and payments associated with the International Mobility program (relocation expenses, housing allowances, cost-of-living adjustments, foreign service premiums, education allowances, and other special allowances and payments) are paid by the host country. However, in the U.S., the costs of these benefits are held at the parent, IUSA.

In 2010, the Company created special Internal Orders (with codes ending in “014”) within the SAP system to collect the special allowances and payments associated with the program. These expenses are booked at IUMC, even for those expatriates hosted by an operating company, and then charged to IUSA as part of the month-end allocation process. The labor costs of expatriates assigned to IUMC, after the special expenses are charged to IUSA, are direct assigned or allocated to the U.S. affiliates depending on the work function, in the same way as U.S. employees. For non-U.S. employees assigned to the U.S., the base compensation and allowances are determined by the Mobility Management Department in Spain.

26. There have been some lapses in the Company’s compliance with the expatriate assignment policies and procedures, but these appear to have been corrected.

In 2010, the IUMC Regulatory department examined how the expatriate allowances were being charged and noted that amounts had been charged to the operating companies that should not have been. The charges were subsequently reversed and charged to the holding company and the new “014” Internal Order codes for expatriate allowances noted in Conclusion #25 were developed to post future allowances to the holding company. Liberty reviewed an example of this in the transaction test.

The accounting treatment for the salary of the first expatriate hosted in the U.S. did not follow the Company's stated procedures. The salary was booked in the U.S. rather than in Spain, which Liberty confirmed in the transaction test. However, this did not materially affect the U.S. costs, since the costs would have been charged back to the U.S. according to the current policy eventually. Other expatriate transactions Liberty observed in the transaction test appear to have followed the expatriate company's policy's accounting procedures. The transaction test included examples of both U.S. expatriates working abroad and non-U.S. expatriates working in the U.S.

An internal audit report dated May 10, 2011 noted several lapses in the Company's compliance with its expatriate assignment policies and procedures:

- Five employees had not signed the international employee agreements.
- There were no comprehensive policy and procedures (as noted in Conclusion #25).
- The SAP Payroll module was posting the employee allowances to the employees' home cost centers rather than the "014" Internal Orders, causing the employee allowances to remain in the home cost centers rather than the holding company.
- There were no monthly accruals for the annual charges for employee salaries from ISA to IUSA.
- The cost of fleet vehicles driven by expatriates was being charged to the operating companies owning the vehicles rather than to IUSA.

The Company's management has responded to these findings, addressing them as follows:

- Fully signed international employee agreements were received by June 20.
- A draft comprehensive policy and procedures document was completed on July 22, which will be updated as the procedures evolve.
- An audit completed on July 28 verified that the SAP Payroll module was updated to properly assign employee allowances to the "014" Internal Orders and thus assign them to the holding company.
- An audit completed on June 16 verified that accruals for the ISA charges had begun.
- An audit completed on June 17 verified manual journal entries had been posted to move the 2010 cost of the fleet vehicles from the operating companies to IUSA. The Company planned to make an additional correction for the 2011 costs at the end of the year. The manual journal entries are necessary because the SAP controls do not allow assets, including vehicles, to be assigned from one company to another. To address this problem the Company plans to move to using leased vehicles for expatriates.

It appears that the Company has addressed the procedural lapses and corrected past errors that materially affected the costs of the U.S. operating companies.

27. The Company's financial system and processes provide adequate capability to trace financial transactions, identify the sources of charges, and document cost assignments and allocations.

Using the data the Company provided, Liberty was able to trace most transactions from the transaction source, or a point close to the source, to final booking in the SAP ledgers. In most cases, the source documentation sufficiently supported most of the test transactions and generally explained the reasons for the cost assignment and allocations used. In some cases, Liberty was unable to obtain all the desired source data from the Company but elected not to pursue the data further because of time limitations or the fact that the issues addressed in the transactions were sufficiently covered in other transactions in the test.

Liberty found the justification of the cost assignments and allocations to be reasonable in most cases. In particular, Liberty noted several cases where costs were correctly assigned to IUSA rather than the operating companies. One example of this involved costs associated with the sale of the southern New England gas companies. On the other hand, Liberty observed some cases where general allocators were used but direct assignment or cost-causative allocation appeared to be a better cost assignment approach, as noted in Conclusion #14. Liberty also observed examples that suggested an apparent preference for using the Global Regulated 5 allocator (Global Regulated 3 after the southern New England gas company sale) over the broader allocator to the utilities, Global Regulated 8 ("New Global 5" after the sale). This preference may have arisen because the additional companies in the broader allocator were not using the SAP system, complicating the settlement process. However, the impact of using Global 8 over Global 5 is negligible for NYSEG and RG&E as the table of allocation percentages in the Findings section shows, because these additional companies are much smaller. In some other cases there was insufficient information provided about the nature of the specific work generating the costs to be certain that the cost assignments were appropriate.

Liberty also observed a few errors in the original treatment of a few expatriate labor and expense transactions, which were subsequently corrected, as noted in Conclusion #26. Some additional observations from the transaction test are noted in the other conclusions of this chapter.

D. Recommendations

1. **Change the identification of transactions as convenience payments to distinguish pass-through payments from expenses incurred in providing inter-affiliate services.** *(Conclusion #2)*

The Company currently includes within the category of "convenience payments" in inter-affiliate invoices two types of transactions: (1) simple pass-through payments by one affiliate on behalf of another and (2) some vendor payments and employee expenses associated with services provided by an affiliate for another. It is important to distinguish the second category, which contains true costs incurred in providing inter-affiliate services, from the first, which does not.

The Company currently classifies all inter-affiliate transactions originating outside of the service company, IUMC, as convenience payments unless they are entered into SAP through the time-entry system. This means that all non-IUMC vendor payments and employee expenses, except mileage and per diem, incurred on behalf of other affiliates are treated as convenience payments. IUMC can and does separate transactions originating outside of the time-entry system, such as vendor payments and employee expenses, into those that are costs of inter-affiliate services and those that are simple pass-through payments. However, Liberty found instances in the transaction test in which the IUMC convenience payment categorization was also imperfect; that is, some transactions classified as convenience payments were actually associated with inter-affiliate services.

The Company has recently instituted a policy change to reduce the amount of multi-affiliate vendor invoicing, which has had the effect of reducing the magnitude of the convenience payments. However, this policy change does not address the underlying issue that some non-labor charges are legitimate costs of providing inter-affiliate services. Because the Company has the capability of making that distinction for service company transactions, it should be straightforward for the Company to extend that capability to the other affiliates. In addition, the Company should improve the controls on the process to help ensure that the classifications are correct even for the service company transactions.

2. **Review and update the language of the inter-affiliate service agreements to reflect the current practice for affiliate transactions.** *(Conclusions #6 and #11)*

The current NYSEG and RG&E service agreements contain obsolete and misleading language. This is particularly true of the cost allocation provisions. The utility-provider agreements contain outdated provisions for allocating utility-provider costs, which is not the Company's practice. The IUMC-provider agreements contain references to allocators that are not used and do not correctly document allocators that have been modified as a result of divestitures.

The value of these agreements would be much improved if this confusing and outdated language were removed. This could be accomplished readily as part of the next annual budget and service agreement execution process. An internal company audit completed in May 2011 noted that there were a number of outdated references in the Company's cost manual, which contains virtually the same language as the service agreements. This was supposedly corrected in the middle of 2011, but Liberty had not viewed the updated language. To the extent that the corrected language addresses Liberty's concerns, it could be incorporated in updates to the service agreements.

One other beneficial step would be to document the precise steps used within SAP to accumulate and assign costs. This is more detailed than necessary for the service agreements and cost manual, but would be a valuable stand-alone document.

The service agreements also be amended to address explicitly the transfer of intellectual property and other intangible benefits among the affiliates. An alternative would be to amend the Code of Conduct for IUSA employees to make clear that the transfer of intellectual property among affiliates requires compensation.

3. **Tighten the controls that should prevent inter-affiliate billing without a service agreement.** *(Conclusions #7 and #12)*

The Company has table-driven controls in the SAP system to prevent inter-affiliate charging and billing unless there is a service agreement between the affiliates. However, these controls are incomplete and can be subverted, thereby undermining the service agreement process. The controls do not apply if one of the affiliates does not use the SAP system. Additionally, the table edits can be lifted for payroll transactions, which constitute the majority of the inter-affiliate charges, in order to prevent payroll delays. In such cases, the Company relies on supervisors approving the time-entries to ensure proper cross-company charging. This is an inherently error-prone process.

Liberty found cases, as noted in Conclusion #7, where inter-affiliate charges were billed without service agreements during 2009 and 2010. Liberty notes that there were no instances of affiliate transactions without corresponding service agreements during the portion of 2011 reviewed in detail during this audit (January – July 2011). Thus, the Company may have rectified lapses in the controls during 2011. However, the Company should review the control system and eliminate the situations where the controls can be so easily by-passed.

4. Improve the timeliness of inter-affiliate bill payments. *(Conclusion #9)*

Liberty found that 20 percent of all inter-affiliate invoices involving NYSEG and RG&E were paid late, including a significant number more than 100 days late. As much as 25 percent of the invoices for payments to NYSEG and RG&E were late. The service agreements state that there will be 0.5 percent late payment fee for every month there is an outstanding balance, but the Company does not abide by the service agreements by requiring these late fees. The Company should either institute processes that assure more prompt payment of invoices or begin charging the late fees in accordance with the terms of the service agreements to incent prompt payment of the invoices.

5. Improve employee training and develop more complete policy documents to encourage more direct and cost-causative charging of service company costs. *(Conclusions #12, #13, #14, and #19)*

The Company's stated policy is to direct charge affiliate transactions as much as possible. However, Liberty found that only approximately 25 percent of service company charges have been direct charged to affiliates. Most of the remaining charges are allocated through general rather than cost-causative allocators, although Liberty found that allocation amounts would not vary significantly if the existing cost-causative allocators were used more extensively.

Liberty also found that there is limited training and documentation of Company policies available to employees to guide them in complying with the state corporate affiliate transaction policies. This may contribute to the limited amount of direct charging. Additionally, the Company's internal Code of Conduct document contains wording that conflicts with the requirements of the New York Code of Conduct agreement with the Commission.

The Company should improve its affiliate charging policy documentation and employee training and increase its diligence in implementing the existing policy of preferential direct charging. Although Liberty found limited impact in using the existing cost-causative allocators over the general allocators Liberty recommends that the Company continue to review the allocation factors to make sure that a better allocation of costs could be achieved through more extensive use of cost-causative allocators, including the potential of adding new allocators based on different quantities.

Load Forecasting – Electric and Gas

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IV. Load Forecasting - Electric and Gas

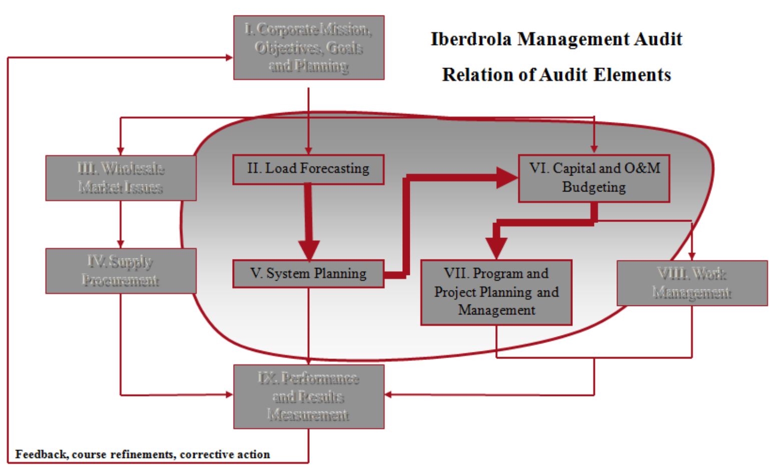
A. Background

The Companies have established three different forecasting processes for electric operations and three for gas operations. Basically, the three processes are independent, and address operational needs for the near-term, intermediate and long-range planning requirements. We found, with the possible exception of the very short-term forecasting process, namely, the day ahead forecast, forecasting was considered a secondary responsibility operating under minimal senior management attention, direction, and coordination. The three electric forecasting processes are performed by three separate units within the integrated IUSA organization, and the three gas forecasting processes by two separate units, one of which is in common with an electric process.

1. The day-ahead electric peak demand forecast is prepared daily by the Supervisor of Electric Supply, who manages the day ahead and real time trading desk.
2. The intermediate electric and gas forecasts (1 to 5 years) are prepared by the Rates and Regulatory Economics section.
3. The long-term electric peak demand forecast (5 to 10 years) is prepared by engineers in the System Planning group.
4. The long-term gas peak demand forecast and the gas day ahead (1 to 5 day) forecasts are performed within the Gas Supply group.

The forecasting processes use different modeling techniques, input data and forecast assumptions. Furthermore, there are no internal control processes to vet each of the forecasts, seek consensus as to appropriate forecast assumptions, or develop common understanding of forecast uncertainty.

Peak demand forecasting sets the basis under which sales and revenues are projected, as well as corresponding estimates of operational and maintenance expenditures. Longer term forecasts assist the Company in its projecting of system requirements, which then help drive the Company's construction program and capital budget.



An energy forecast can be created with as little as a piece of graph paper and a straight edge, but the bank of knowledge gained from the forecast process should go much further in pinpointing the socio-economic factors that have historically had the most influence on the demand for and consumption of energy, in determining those trends in the future and, most importantly, in assessing whether those historical relationships will or can be changed over time. Conservation initiatives and demand management present two examples of how a utility can influence future consumption patterns.

That the economic downturn has reduced the growth in energy demand and consumption to minimal levels does not negate management's need for ongoing due diligence in its forecasting process. Shifts in usage patterns could result in over or under building transmission and distribution networks or errors in estimated revenue requirements and earnings projections.

Planning should reflect an integrated set of processes. Demand and use forecasting, resource planning, and system operations planning are key elements of a properly integrated capital planning and budgeting program. Demand and use forecasting activities support many utility planning functions. Capital resource requirement plans build from long-term aggregate forecasts of use and peak demand growth. More localized forecasts (for example, number and type of customers, consumption and contribution to peak) support planning for extension of distribution systems. Forecasts of operations and maintenance needs and increased customer service requirements are used in the planning processes for personnel and support facilities. Effective forecasting also requires consideration of the effects of demand side management, energy efficiency, weather, and other developments.

We have examined the models used to forecast load requirements, the processes for determining their key inputs and assumptions, and the appropriateness of the inputs and assumptions selected for use and how they have changed in recent years. We also examined the accuracy of recent forecasts in order to assess whether any problems or gaps have substantially affected that accuracy. In performing this sample review, we were mindful of the need to avoid hindsight analysis and of the fact that forecasting is, even when performed well, an uncertain venture.

Effective forecasting also requires well organized, experienced personnel. We sought to determine where NYSEG and RG&E have located forecasting responsibility and how they have coordinated forecasting needs and outputs among their electric and natural gas businesses. We also examined the effects that the New York System Operator (ISO) has on electric load forecasting for NYSEG and RG&E, and how the Companies have accommodated that role in their own processes and activities.

In order for us to effectively investigate the performance of the energy and load forecasting process we identified and followed these nine evaluative criteria:

1. Forecasting should be supported by comprehensive, accurate models that are sufficiently robust to address the drivers and uncertainties faced by New York electricity and natural gas operations.
2. These models should be subject to continual revision and updating.
3. Forecasting should be conducted by well-trained and experienced personnel familiar with the capabilities and limits of models used, with recent and likely changes in economic and other factors that affect load in the serving area, with recent experience at other similarly situated enterprises, and with the differences in factors that affect NYSEG and RG&E's electricity and natural gas businesses.

4. The accuracy of forecasts should be checked and appropriate adjustments made to future forecasts and methods.
5. To the extent that forecasting depends upon different organizations, there should be strong integration of efforts to assure consistency of assumptions, timely inputs, and coordination of results
6. Forecasts should reflect public policies and guidelines for demand- and use-affecting programs, should include robust estimates of their effects, and should address their uncertainties fully.
7. Forecasting for the electric and natural gas businesses should use consistent assumptions, be conducted on a reasonably contemporaneous basis, and recognize interdependencies.
8. Forecasts presented to the Commission for use in regulatory proceedings should be current, use inputs consistent with those used for internal forecasting purposes, and be sufficiently transparent to support adequate stakeholder and Commission review.
9. Company forecasting processes and results should be consistent with what is needed for effective coordination with NYISO's role in forecasting for the state.

B. Findings

1. Organization and Staffing - Electric and Gas

The Companies differentiate electric energy and peak demand forecasting into three defined periods: near-term (day ahead), intermediate (1 to 5 years) and long term (5 to 10 years). For each period, a separate functional group prepares the forecast, the model development and the adoption of forecast assumptions. The following table identifies each electric forecast, it application, and organization that is responsible for its development.

Electric Forecasts

Forecast Period	Duration of Forecast	Application	Responsible Organization
Near Term	1 Day	NYISO Day Ahead Market Hourly Demand	Electric Supply
Intermediate	1 - 5 Years	NYISO System Coincident Demand Monthly Sales and Revenues	Rates & Regulatory Economics
Long Term	5 – 10 Years	Transmission Planning	Electric Planning

Three sets of processes collectively comprise gas load forecasting at IUSA: the long-term forecast of sales and revenues, the design day and design winter forecast, and the day-ahead (one to five day) forecast. The following table shows each gas forecast, its application, and responsible organization.

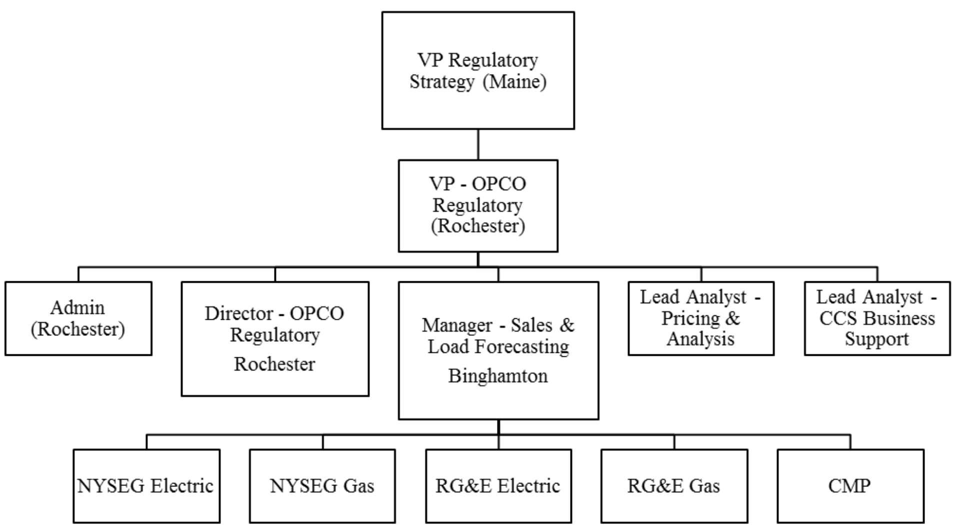
Gas Forecasts

Forecast Period	Duration of Forecast	Application	Responsible Organization
Near Term	1 - 5 Day	Gas Dispatch	Gas Supply
Intermediate	5 Year	Monthly Sales and Revenues	Rates & Regulatory Economics
Long Term	Undefined - until superseded	Design Day and Design Winter, for Gas Supply and System Design	Gas Supply

The intermediate forecast is developed in the IUSA load forecasting organization, which is the same group that develops the electric forecasts. The day-ahead and long-term (design day and design winter) forecasts are developed in the Gas Supply organization and are addressed in Chapter IX- Supply Procurement - Gas.

The intermediate forecasts are used to project sales and revenues for both the electric and gas businesses. They are prepared in the Sales & Load Forecasting group of the Rates and Regulatory Economics organization, which reports to the Vice President - OPCO Regulatory, who in turn reports to the Vice President, Regulatory Strategy. The organization is depicted in the following chart.

IUSA Sales and Load Forecasting Organization



The chart shows the distribution of the supervisory functions among the Rochester, Binghamton and Maine offices.

IUSA utilizes a committee to review and sign off on the sales and load forecasts, usually in August, as a basis for budgets. It includes the VP, Controller and Treasurer, the Vice President Energy Supply/Transmission Services and the Vice President, Regulatory. The committee has no written charter or written procedures. A schedule is developed each year, triggered by the IUSA annual budgeting cycle.

2. Forecasting Methods - Electric

a. Near Term Forecasting

The Near Term Forecast is a day-ahead forecast prepared by the Supervisor of Electric Supply. This person is responsible for managing the Companies' bidding into the NYISO Day Ahead and Real Time markets. Each weekday morning a load forecast is electronically submitted to the NYISO. This forecast commits the Companies to a specified level of supply requirements for the following day. Over or under forecasts can be adjusted in the NYISO's real time markets. Typically, less than 20 percent of the day ahead market bid is adjusted up or down in the real time market. Reasons for modifying the day ahead forecast include:

- Day ahead forecast error
- Changed weather conditions
- Modification to projected demand response
- Loss of a contracted generation source
- Change in demand of a major load (*e.g.*, a glass manufacturer needs to shut down an electric kiln)

Modifications to the day-ahead bid can either benefit or cost the Companies and their consumers. For example, an increase in projected demand could increase the unit cost if real-time market prices are higher than the day ahead clearing prices. Likewise, unit costs could decline if the Companies over bid in the day ahead markets and then sell back into a real-time market whose clearing prices had increased. On average, the Supervisor of Electric Supply noted that the Companies achieve about $500,000 in reduced NYISO charges resulting from the two-step day-ahead/real time adjustments and that during 2011, those savings were in excess of $700,000.

The day ahead forecast entails three steps:

1. Energy and load data is updated, including estimates submitted by the municipal electric systems within the NYSEG and RG&E service territories, as well as availability of generation by NYPA or contracted under long-term Purchase Power Agreements.
2. Next a data base developed by the Company of historical weekday and weekend load shapes is used to estimate the next day's hourly load characteristics. For example, hourly load shapes for a typical Tuesday in July following a Monday holiday can be plotted.
3. Finally, an acquired model called AANSTLF (Advanced Artificial Neural-Network Short Term Load Forecaster), which was originally developed by EPRI, uses hourly weather forecasts along with historical load shapes to project the following day's hourly loads.

While this process appears highly analytic, it is as much an art as a science and calls on the many years of experience of the forecaster, in this case the Supervisor of Electric Supply, to balance and adjust the forecast as anomalies occur.

b. Intermediate Forecasting

The intermediate forecast of energy and peak demand is developed within the Rates and Regulatory Economics section. The Manager of Sales and Load Forecasting is responsible for both the gas and electric forecasts and has two dedicated staff members to develop the electric forecasts, one for Central Maine Power and one for the New York utility systems. The latter individual has only recently been transferred to the Sales and Load Forecasting section, is not an economist by training and has minimal forecast related experience. Econometric models are developed for each major rate classification including municipal sales and street lighting.

The primary function of the intermediate forecasts is two-fold:

- The one-year system-wide coincident peak demand used by the NYISO's Load Forecasting Task Force (LFTF) develops a New York statewide and zonal weather adjusted peak load growth rate used in the computation of the Installed Capacity (ICAP) rate.
- Monthly and annual energy and sales forecast by rate classification used to project revenue requirements and deliveries.

The Companies use a computer model called Metrix ND, which was created by Itron, Inc. The Metrix ND model is used by a wide number of electric and gas utilities, including the New York ISO. This computer model was developed to provide utilities with a suite of forecasting tools including regression analysis and neural network modeling. The term regression model and econometric model are often used synonymously. However, while regression modeling techniques, like Metrix ND, can be used to create an econometric forecasting model with little or no economic or statistical knowledge, there is a danger that the model's specification will lead to biased or misleading results without the expert analysis and assessment of a trained econometrician.

There is an inherent problem with econometric modeling of energy consumption, in that conditions that must be met in order to have a high degree of confidence in the forecast are nearly always violated to some degree. It takes a seasoned analyst to assess to what degree those rules are violated and how that might influence the forecast. Generally, the fit of the historical data to the regression equation is viewed as the most critical factor. However, measures of fit, including those used by the Companies, can be misleading if either the historical trend of key variables are highly correlated from year to year – this is called autocorrelation, or there is a correlation between independent variables – and this is called multicollinearity. While the companies do test for degree of fit, as indicated in testimony before the NYPSC, it appears as if they do not use the set of other statistical measures to evaluate such conditions as autocorrelation or multicollinearity.

The regression models for residential, commercial and industrial classes of customers consider five categories of explanatory or independent variables:

- Economic
- Electric Price
- Weather
- Demographic
- Calendar (to differentiate month of year).

The following table identifies the specific variable for each customer classification:

Customer Class	Economic	Price	Weather	Demographic	Calendar
Residential	Real Disposable Personal Income	Average Res. Price adj. by CPI	Weighted Average of deviation from normal HDD & CDD	Number of Res. Customers	Dummy Variable[1]
Commercial	Gross Regional Product	Ave. Com. Price adj. by GDP Price Deflator	Same as Residential	Number of Res. Customers	Dummy Variable
Industrial	Upstate NY Real Manufacturing GDP	Ave Ind. Price adj. by PPI	Same as Residential	Upstate NY Manufacturing Employment	Dummy Variable

Once the econometric models are derived from a thirty-year historical data base, economic and household forecasts obtained from Moody's Economy.com are used to develop each class specific monthly energy forecast. Historical load factors are used to convert annual electric consumption to peak demand estimates.

The Companies do not evaluate the degree of certainty associated with each forecast based on either modeling error or independent variable forecast error. Nor do they assess a range of scenarios that might include loss of manufacturing facilities or price elastic response to rising electric commodity prices.

c. Long Range Forecasts

The long range electric peak demand forecast is prepared by the Electric System Planning section for both the 13 region divisions of NYSEG and for RG&E. The methodology is substantially the same for both operating Companies.

Following each capability period (summer and winter), peak loads are derived for each division. For NYSEG's 13 divisions, municipal and electric cooperative loads are accounted for and adjusted for degree of coincidence. Using the previous ten-year period, a regression analysis determines each division's annual growth rate, which is then used to forecast peak demands for the following ten-year period. This growth rate is applied to the highest peak demand that occurred during the prior ten-year period, and then compounded by that growth rate thereafter. The historical peak loads are not adjusted for weather, nor is the forecast adjusted for potential demand response initiatives.

The peak load forecasts are periodically monitored as projected peaks become actual and transmission projects can be either accelerated or deferred, as required.

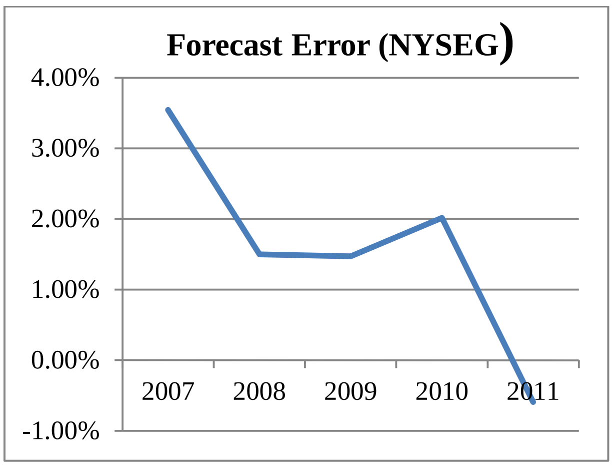
[1] A Dummy variable is used to tag whether a certain condition exists or not. For example, if the data point is for January, the dummy variable is 1 and 0 for all other months.

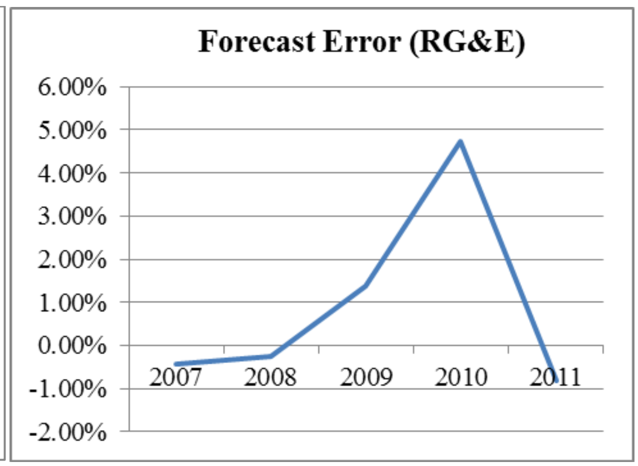
Finally, there is no apparent internal review process under which senior management is presented the long range forecast before the system planners begin their transmission network analysis. The system planners also do not produce a range of forecasts in order to consider forecast uncertainty and its impact on transmission requirements.

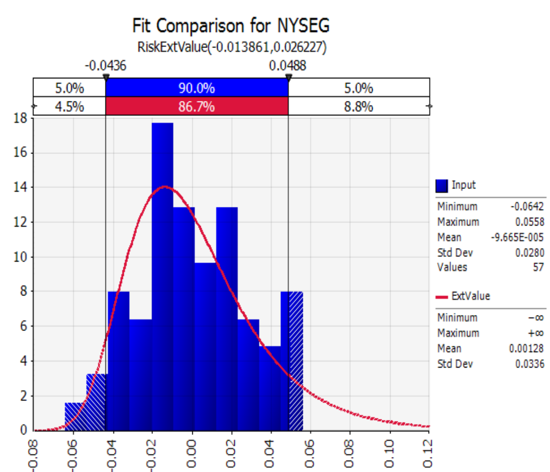
3. Forecast Performance - Electric

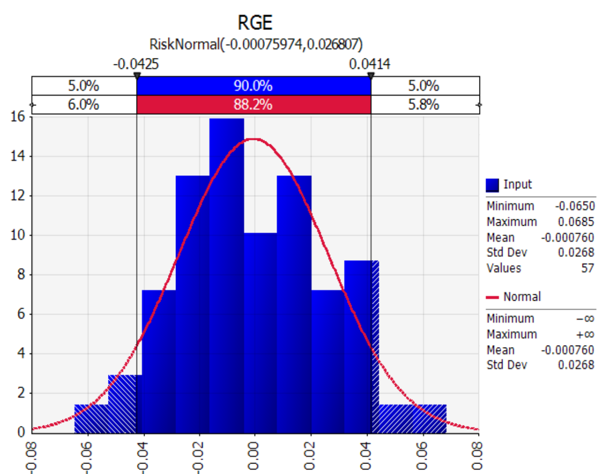
The intermediate and short-term forecasts were evaluated for historical accuracy and systematic error band. For the one year peak load forecast, we found that the percentage error for both NYSEG and RG&E were biased to the high side. For NYSEG, the forecast was higher than actual in four of the last five years and for RG&E the forecast was higher in only two of the last five years, although the degree of error was much greater in 2009 and 2010.

When looking at the longer term monthly forecasts, developed with the same econometric models, the distribution of error was centered very close to zero and the error band for both C-companies was plus or minus 4 percent with a 90 percent level of confidence.

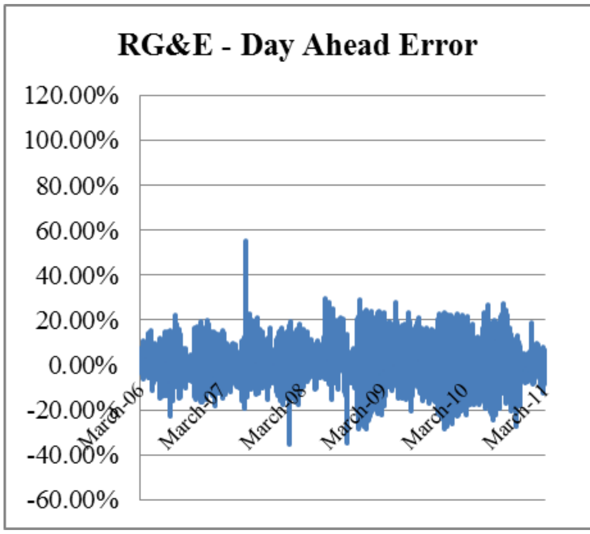


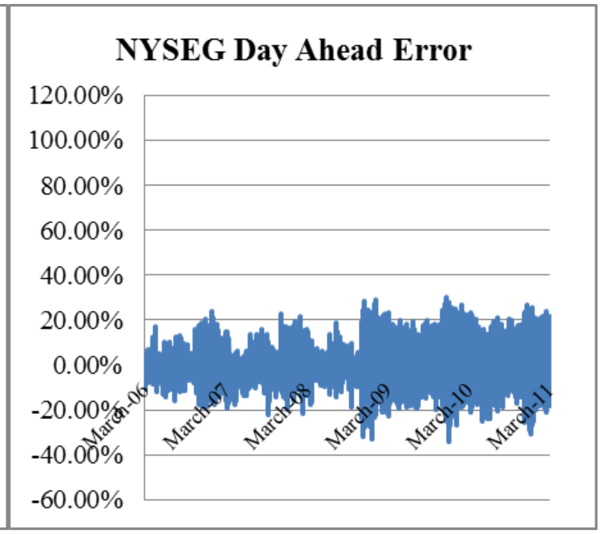






The day-ahead forecast was also evaluated over the last five years. The average percent of error was about -.3 percent for NYSEG and 1.26 percent for RG&E which is less than the industry average of about 3.5 percent. The following graphs, do paint a slightly different picture as the hourly forecast error can range by plus or minus 20 percent, although it does not appear biased on the high or low side. Finally, it can be observed that the error band seems to be increasing over time, especially since 2009. To validate this observation, a statistical test was performed on the error trend between 2006 and March 2009 and then between April 2009 and March 2011. It was found that while the actual average error declined in the latter period, the magnitude of the standard error, a measure of volatility, nearly doubled.





No analysis of the long-term system planning forecast was performed, becauseit is not really a forecast at all, but rather a worst case "best guess" by assuming the ten-year forecast would be at least as great as the highest peak load unadjusted by weather conditions. It is neither an economic based forecast nor a trend line estimate. To compare forecast to actual could only validate the process should the resulting peak load be, by happenstance, approximately correct.

4. Gas Intermediate Term Forecast

IUSA's intermediate term forecast is developed in the Regulatory group for projecting revenues, gas costs and volumes, procuring gas supply, and the gas commodity hedging program. Historically, the long-term gas forecasts have looked out three years. In 2011, for the first time, IUSA prepared a five-year forecast, for the period 2012 - 2016.

a. The Forecasting Model

IUSA develops its forecasts for residential customers using an average-use-per-customer model, and on a total class basis for commercial, industrial and municipal customers. The company uses the Metrix ND software, the same models that it employs for the electric forecasts, with some differences associated to account for the differing characteristics of electric and gas loads. The differences include a per customer forecast for gas, as compared to a demographic variable for electric, and an empirical weather normalization methodology rather than a weather variable.

i. Weather Normalization

Rather than include a weather variable, the Company weather-normalizes the historical data prior to inputting it into the models, for all customer classes. To do so, the Company subtracts base load deliveries from actual total deliveries for each year in a rolling ten-year period. This was a recent change from a rolling 30 year period, brought on by a recent Commission change of policy. Base load is defined as the average of deliveries during the two months having the lowest level of consumption during the calendar year, which are assumed to be non-weather-related. All other deliveries during the year are considered weather-related and are divided by billing month heating degree days to generate the expected load per heating degree day per month. Those results are then multiplied by the normal heating degree days for each billing month and then added to the base load amounts.

ii. The Residential Sales Forecast

The residential forecast is the product of forecast average weather-normalized usage per customer (“sales model”) multiplied by forecast numbers of customers, calculated on a monthly basis.

The residential sales model is an econometric model that develops the average monthly per customer use using the following variables: real residential price, several dummy (binary) variables, and the number of billing days per month.

The Companies find the model to be very accurate, with essentially zero variance.

The forecast of the number of residential customers is developed from an econometric model that uses Moody's Economy.com forecast of the number of households in Upstate New York as the main explanatory variable. The Company also finds this model to be very accurate, explaining almost all of the variation in the residential class. That is the unsurprising result that the number of customers is highly correlated with the number of households.

iii. The Commercial, Industrial and Municipal Sales Forecasts

The commercial model uses the following variables: real commercial price, real non-manufacturing GDP, monthly binary variables, and number of billing days per month. The industrial model uses the following variables: real industrial price, Upstate manufacturing employment, monthly binary variables, and number of billing days per month. The municipal model uses the following variables: real municipal price, number of Upstate households, monthly binary variables, and number of billing days per month. This assumes that the key explanatory variable for municipal customers is number of households. The Companies also make "out-of-model" adjustments for anomalies not reflected in historical data, such as an existing large customer bypassing the system, based on input from Key Account Managers or other sources. The number of customers in the commercial, industrial and municipal classes is forecast using a single variable (”exponential smoothing”) model.

iv. The Transportation Forecasts

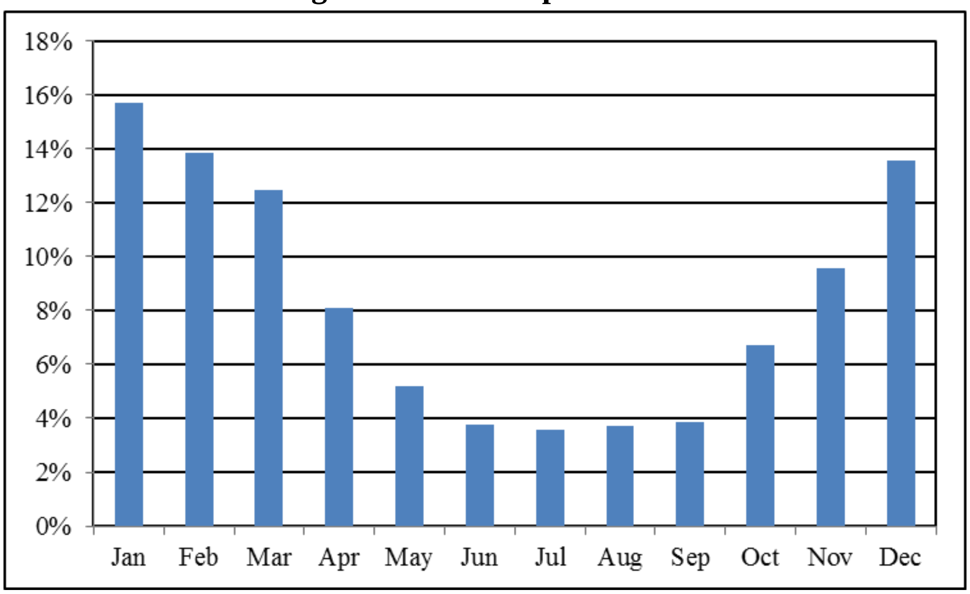
The Company develops forecasts of the numbers of transportation customers, by customer class, using a single variable forecast for each class, and then multiplying the numbers of customers by the weather-normalized average use per transportation customer of the same month in the preceding 12 months.

Overall, the Company believes it has validated all its long-term forecasting models through strong ”goodness of fit” statistics.

b. Converting the Annual to a Monthly Forecast

The long-term forecast is the basis for the gas supply plan and the hedging plan. To be useful for those purposes, the annual volumetric sales must be converted to a monthly forecast. It is first increased by a loss factor, adjusted to match billed days and calendar days, and then spread over the forecast year to develop the monthly gas supply forecast. The monthly supply forecast is developed by deriving a load shape over the 12 month period based upon the average weather-normalized load shape for the previous five years. For example, the average load shape (i.e., monthly load as percent of average annual load) for the five years period 2005 - 2009 is depicted in the graph below:

Average Gas Load Shape 2005 – 2009



5. Forecast Performance - Gas

There are significant variances between forecast and actual sendout. The tables below show the difference between normal weather, expressed as percent difference from projected HDDs based upon IUSA's 1992 study (addressed in Chapter IX Supply Procurement - Gas) and consumption at the burnertip, expressed as variance from forecast, for the years 2006 to 2010.

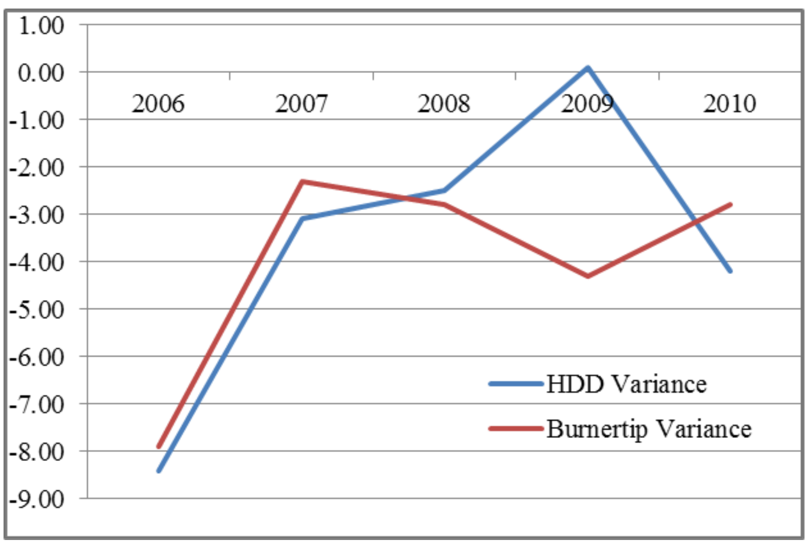
Comparison of Forecast Weather to Forecast Consumption

NYSEG	HDD Variance	Burnertip Variance		RG&E	HDD Variance	Burnertip Variance
2006	-8.4%	-7.9%		2006	-17.1%	-8.2%
2007	-3.1%	-2.3%		2007	-5.5%	-1.3%
2008	-2.5%	-2.8%		2008	-5.2%	-0.9%
2009	0.1%	-4.3%		2009	2.6%	-5.6%
2010	-4.2%	-2.8%		2010	-1.1%	-2.5%

The results in the tables lead to two conclusions. First, the HDD variance appears to suggest that 4 out of the 5 years were warmer than forecast, *i.e.*, warmer than normal. This difference is attributable, at least in part, to the Company's use of a weather study performed in 1992 using the prior 40 years of data, and only for Binghamton.[2] The consumption variation from forecast, on the other hand, is developed using the prior 10 years of history. Thus, the consumption forecast uses data from 2001 - 2010 and the design weather forecast uses data from 1951 - 1991.

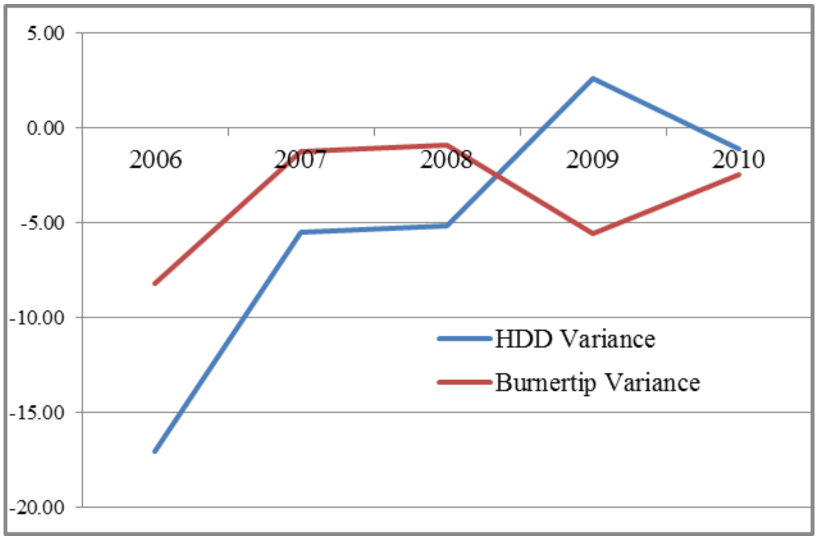
Second, the variation between forecast weather and forecast consumption shows no discernable pattern. The graphs below depict the data from the tables above.

NYSEG



[2] The study actually looked at weather in Binghamton and Buffalo, but then used the colder weather experienced in Binghamton as its final recommendation.

RG&E



This suggests that unexplained variables are affecting the consumption.

6. Variance Analyses - Electric and Gas

Forecasting staff performs three review cycles during the year to compare actual with forecast results of volumes, customers, and revenues, typically in the February, April-May, and July-August time frames. They make revisions only if there are major changes. Historically, they have used a 3 percent threshold as a trigger to require further investigation of cause of the variation, although that does not necessarily result in a revision. There is no specific threshold that triggers the revision process. Usually, the July-August revision includes an update to the sales forecast in preparation for the upcoming budget development.

If they determine that a revision should be performed, they rerun the models and change the forecast if the difference is deemed significant.

C. Conclusions - Electric and Combined

1. **The intermediate forecasts are overly simplistic, and fail to capture the broad range of economic and demographic uncertainties facing the Company.** *(Recommendation #1, #2, #4)*

Forecasting for the electric and natural gas businesses should use consistent assumptions, be conducted on a reasonably contemporaneous basis, and recognize interdependencies. It appears as if the intermediate gas and electric forecasts do apply consistent assumptions. The economic driver forecasts are all produced by Moody's Econometrics. The short-term and long-term forecasting models are based on models that rely on historical trends as opposed to correlations with economic and other factors.

The Company does not perform any sensitivity, scenario or risk analysis. The long-range forecast methods are not based on sound economic principals, fail to capture socio-economic trends and are void of any risk and uncertainty analysis.

Electric

OPCO Regulatory is responsible for the development of energy and peak load forecasts, customer forecasts and revenue projections. The unit also produces the one year coincident system peak demand submitted to the NYISO's Load Forecasting Task Force used to develop the following year's Installed Capacity (ICAP) rates.

The annual forecasts are developed during the Spring, with periodic revisions performed up to three times a year. The revisions are only performed if it is viewed that material changes in the output are anticipated. For each forecast, only the "expected" forecast is produced. The Company makes no attempt to produce upper and lower boundaries, probability distributions or uncertainty analyses. Its argument is that the Revision process provides adequate care to assure accurate forecasts.

Furthermore, the Company does not perform scenario analysis or another form of risk/uncertainty analysis whereby a number of alternative futures are considered. Examples might include:

- The loss of a major industry
- Price elastic response to rising electric prices due to the termination of existing nuclear PPA's (Ginna and NMP)
- Market penetration of electric vehicles
- Impact of time dependent rates in support of Smart Meter installations.

It is common practice for electric utilities to evaluate the range of uncertainty of their energy and peak demand forecasts. As a minimum, a high-low band is developed whereas more sophisticated forecasting methods include scenario and uncertainty analysis. By simply updating the forecast during the year provides little opportunity to consider, proactively plan for and execute significant shifts in consumption or demand.

Gas

The residential forecast develops a single "point estimate" for each monthly point on the forecast based on normal weather and a single variable, use per customer. It does not attempt to forecast alternative scenarios for colder- or warmer-than-normal weather, potential variations in historic customer growth trends (which are embedded in the methodology), or the potential effects of the ongoing energy efficiency programs.

The commercial, industrial and municipal forecasts are also point estimates based on normal weather, and in lieu of use per customer use a price variable and non-manufacturing GDP, manufacturing employment or number of households, respectively.

The Company does state that it is currently working on plans to comply with the Commission's Energy Efficiency Order but has not determined how those plans might impact planning.

The increase in the forecasting period from three to five years, first performed in 2011, was long overdue. The shorter forecast was, unfortunately consistent with the lack of a system planning function, as discussed in Chapter IX, Supply Procurement - Gas.

2. **Reviews and revisions to the intermediate forecasts are informal and based on subjective, vaguely defined criteria.** *(Recommendation #2)*

Forecasting staff compares the forecast to actual results periodically, on a reasonable review cycle. Staff has an informal "rule-of thumb" that any variance in excess of 3 percent will trigger a deeper look, but the depth of the analysis and the decision as to whether to revise the forecast are dependent upon the analyst's assessment of causes and judgment. The choice to adopt a revised forecast (i.e., Rev. 1, 2, or 3), is based on loose criteria, is left to the forecast staff and not vetted by senior management.

3. **There is no process to revise or update the electric long-term forecast transmission model for planning purposes other than the annual updates of historical peak loads.** *(Recommendation #2)*

Liberty found that the accuracy of the various divisional forecasts was only addressed during the next round of annual updates in historical data. As discussed above, the long-range forecast is based upon the highest peak demand for a given division that occurred over the prior ten-year period and escalated each year by the linear trend or growth rate derived from the ten-year historical data base. For each annual forecast, two of the ten data points, the first and last year, are updated.

4. **IUSA is short on experience and capabilities in the planning and forecasting areas at the staff level.** *(Recommendation #2, #3)*

Forecasting should be conducted by well-trained and experienced personnel familiar with the capabilities and limits of models used, with recent and likely changes in economic and other factors that affect load in the serving area, with recent experience at other similarly situated enterprises, and with the differences in factors that affect NYSEG and RG&E's electricity and natural gas businesses. The intermediate forecast is now being performed by an individual with little or no economic or forecasting modeling experience except for attending an ITRON three-day training seminar on their METRIX ND forecasting model used by NYSEG/RG&E. The section manager and the Vice President of Rates and Regulatory Economics do have significant modeling experience, but it is unrealistic to assume that they can provide the ongoing oversight given their other responsibilities within the New York utilities as well as Central Maine Power.

Employee turnover has been a contributing factor to this issue. The group lost two experienced people to a retirement program in early 2011, only one of whom was replaced, and he by an inexperienced person with no background in this area. The group does not have a formal or informal training program; training is strictly on-the-job.

The electric long range forecasting process is managed by a transmission engineer with no significant economic or forecasting training. Given the simplicity of the long-range forecasting methods, while on the one hand, extensive economic training is really not required, but on the other, the forecast models provide little comfort that the peak load forecasts are robust enough to capture economic or other factors that might affect consumer consumption trends.

5. **The various forecasting and planning groups and functions are weak in integration and communications, both laterally and vertically.** *(Recommendation #1)*

To the extent that forecasting depends upon different organizations, there should be strong integration of efforts to assure consistency of assumptions, timely inputs, and coordination of results. The forecasting organization is geographically fragmented, with managerial staff in Maine, Rochester and Binghamton and analytical staff in Binghamton. This tends to inhibit communications, knowledge transfer and general awareness of what is going on in the organization.

The three electric forecast processes are performed by separate groups and no attempt is made to coordinate assumptions, models, and results.

Currently the Companies generate three different energy and load forecasts by three different business units using potentially inconsistent methods and data assumptions. The three electric forecasts include: a very short-term forecast for bidding into the New York ISO day ahead markets, intermediate-term forecasts for sales and revenue projections (as well as the one-year forecast used by the New York ISO load forecasting task force to derive the following year's ICAP computation), and a 5 to 10 year peak load forecasts used by transmission planning to evaluate network requirements. (Transmission Planning has only recently extended the divisional load forecast from 5 to 10 years.)

It appears that the intermediate forecast is presented to upper management for review and sanction, but the other forecasts are developed in isolation without either peer review or upper management approval. Based on this review the following issues of concern are raised:

- Without appropriate oversight and collaboration the intermediate and long-term energy and peak load forecasts are being developed by individuals with limited econometric credentials that expose the Company to forecasts that are either incorrect or biased. Econometric modeling requires a comprehensive understanding of statistical analysis and the associated limitations that such models inherently possess when using limited information that is neither highly correlated nor repeatable.
- The historical trends used to develop the longer-range forecast are by design incapable of estimating changes in peak load growth based on changing population trends, economic output, weather patterns, efficiency and energy management standards, and emerging technologies. By using the highest peak load during the past 10 years as the principal driver could result in a forecast that is inconsistent with socioeconomic trends with the potential for large errors and erratic behavior.
- The potential to have such a wide swing in the long-range peak load forecast, could cause the proceeding system's network analysis (*e.g.*, load flow and stability studies) to produce erratic year-to-year transmission enhancement requirements. This has the potential to result in over or under building, or intermittent slowdowns or acceleration in construction projects – all resulting in inefficiencies and added costs.
- The intermediate forecast, on the other hand, is developed by Rates and Regulatory Affairs which uses an acquired energy forecasting tool called Metrix ND. This software package developed by Itron provides a range of analytical tools including neural networks, multivariate regression, ARIMA and exponential smoothing. Yet, the model is not used by Transmission Planning or the trading desk, nor is the Rates and Regulatory Economics staff ever consulted as to best practice applications for load forecasting.

The three gas forecasts are performed by two separate groups and no attempt is made to coordinate assumptions, models, and results. Forecasting should be a key input to the supply and planning functions, and the load forecasts are used as the basis for supply planning and the hedging program. However, the interactions with other functional groups consist primarily of handoffs of products or information. There appears to be little interaction among Forecasting, Gas Supply, System Planning (to the extent the function exists), and Engineering, and groups have little awareness of activities in other groups.

6. Forecasts do not explicitly reflect public policy directives and guidelines. *(Recommendations #2, #3 & #4)*

Forecasts should reflect public policies and guidelines for demand- and use-affecting programs, should include robust estimates of their effects, and should address their uncertainties fully. None of the forecasting processes address public policy issues including time of use pricing, price elasticity and demand management.

The short and intermediate electric forecasts do exogenously adjust the forecast for estimated demand management impacts; however, the long-range system planning forecast does not. The Rates and Regulatory Economics section, which develops the Companies' intermediate load and energy forecasts, has not commissioned either a load research study or residential customer survey in a number of years. Such studies entail the recording of a statistically valid set of customers differentiated by such differentiators as customer classification, type of housing, income, and family size. Load research provides information on typical load shapes, but the surveys provide the Company with information as to penetration of energy intensive appliances and apparatus, energy efficiency and energy management opportunities, price responsiveness associated with time of use rates, shifts in load factors and migration and other socioeconomic influences on numbers of customers and usage patterns. Using such methods as Conjoint Analysis in conjunction with the load research initiative, economic researchers can extract such information as typical use per appliance and time dependent price elasticity without the need to develop costly end use models.

The important issue is that the current load shapes used by the companies are well out of date and need to be updated. The company argues that the load shapes developed by Primen are used by a number of electric utilities such as Salt River and Southern Company and are considered a viable alternative to load research. With a cost differential of 10 to 1, the use of the Primen developed load shapes makes economic sense especially if the class specific shapes are reasonably accurate. It behooves the company to perform a due diligence assessment by contacting a wide range of users to determine whether they are satisfied and if there are any issues that the companies should consider.

7. Forecasts are consistently applied internally and externally.

Forecasts presented to the Commission for use in regulatory proceedings should be current, use inputs consistent with those used for internal forecasting purposes, and should be sufficiently transparent to support adequate stakeholder and Commission review. It appears that the forecasts used for rate case matters (revenue and sales forecasts per rate classification) are the same as those used internally for business planning and those presented in testimony in NYSEG and RG&E before the NY PSC.

Electric forecasting processes and results should be consistent with what is needed for effective coordination with NYISO's role in forecasting for the state. The forecasts are consistent with the NYISO ICAP computation. The Companies actively participate in the NYISO Load Forecasting Task Force and present their forecast findings and methods to participating stakeholders.

D. Recommendations

Note: The recommendations below apply to the common electric and gas forecasting processes and methods and other electric-only processes and methods. Recommendations applying to the gas-only day ahead and long term forecasting are found in Chapter IX, Supply Procurement - Gas.

1. **Assign responsibility to the Rates and Regulatory Economics group for supervision and coordination of electric energy and peak load forecasting.** *(Conclusions #1, #5)*

For example, while Transmission Planning would continue to develop the actual forecast, the forecast methodology and results should be reviewed and approved by the VP OPCO Regulation.

Second, the forecasting tools used by the Company for intermediate and long range forecasting should be consistent. In other words, the Transmission Planning group should use the Metrix ND software to assure consistency and transparency.

2. **Enhance the intermediate and long-term energy and load forecasting methods.** *(Conclusions #1,#2, #3, #4, #6)*

This should include assessments of alternative growth scenarios and implement risk management analysis that considers the likelihood of future events in the development of load and energy forecasts. It should also address the review and revision process and set specific criteria for triggering revisions.

The forecasting methodology should be improved to include more sophisticated analysis and additional explanatory variables, such as wind speed and previous day's weather.

3. **Enhance the economic and forecasting capabilities and competencies.** *(Conclusions #1, #4, #6)*

Increase the research and regulatory affairs group by one professional to serve as chief forecaster and be responsible for all forecasting processes, both gas and electric, and provide consultation throughout the organization as to forecasting methodology and assessment.

Also, enlist the support of local University expertise. Within both service Company's franchise areas reside several outstanding universities and business colleges including Cornell University, Ithaca college, Binghamton college, University of Rochester and Colgate University, to name a few. Such universities and business colleges offer some of the most advanced skills and expertise at probably the most reasonable price. It is a common practice for local businesses to collaborate with such educational institutions, yet both RG&E and NYSEG are not taking advantage of this opportunity.

4. Perform a comprehensive electric load research program. *(Conclusion #1, #6)*

The companies should obtain more contemporary information on customer usage patterns and time-dependent response prices and other efficiency measures. While an updated load research program would provide the most information, the acquisition of developed load shapes as done by other utilities, may be an economically viable alternative. In either case, the companies need to update their load shapes for all customer classes.

5. Assess alternative forecasting methods. *(Conclusion #1, #6)*

To improve the near term forecasts, IUSA should perform a benchmark comparison of the neural network models developed by EPRI and Itron and (Metrix ND), both currently owned by the Company.

IUSA should perform a best practice assessment of the day ahead and peak load forecasting methods. This should include a review of the forecasting methods used by Central Maine Power in New England and the other New York electric and gas utilities that also trade in the New York ISO day ahead market.

6. Designate an oversight committee to address the management and organization issues. *(Conclusions #5)*

Liberty noted several management and organizational issues in this chapter, including:

- Minimal senior management attention to, direction of, and coordination of forecasting
- Geographical fragmentation of the forecasting group, at both the management and technical levels
- A loosely organized committee to review and approve forecasts, with no charter or written procedures
- Weak communication and coordination within the forecasting organization, and between forecasting and other organizational units
- No specific criteria for triggering a revision of forecasts during the intra-year reviews.

IUSA should create a committee, which would include senior managers and officers, to oversee improvements to the forecasting process and address the issues summarized above and others in this chapter. In the longer term, after the changes are implemented, oversight of the forecasting process should transition to a more formalized review committee, which should supersede the current (unnamed) forecast review committee.

Wholesale Market Issues

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V. Wholesale Market Issues

Since the late 1990s, the New York Public Service Commission has fostered the development of wholesale competitive electric markets throughout the State. The New York Power Pool (NYPP), which was responsible for the management of the statewide bulk transmission network and economic dispatch of generation, was transformed into the Independent System Operator (NYISO). The role of NYISO is to assure the development and operation of a reliable and secure transmission network; provide the forum for independent power producers to both site new generation and be confident that transmission networks will provide access to retail markets; and manage the competitive electric market place by which day ahead and real time energy sales can be transacted. The NYISO also manages other markets including installed capacity, demand response and transmission congestion contracts. The primary structural differences between the "old" NYPP and the NYISO, from a public policy perspective, are the range of stakeholders and the transparency of decision-making. The NYPP was jointly owned by the electric utilities in the State including NYSEG and RG&E, who also owned both the transmission networks and the electric power plants.

Today, the NYISO, a non-profit corporation, provides the mechanism by which a wide range of stakeholders, including the transmission owners (TO), independent power producers (IPP), power marketers, retail consumer representatives and regulatory agencies, participate in the oversight and decision-making processes managed by the NYISO. The incentive to transform the NYPP into the NYISO was in response to the perceived failure of the regulated market to maintain generation construction costs and rising surplus capacity. The NYPP operated under a "share-the-savings" protocol, where the electric utilities' generation was dispatched based on lowest operational costs regardless of owner. The restructured market was not revised for competition's sake alone, but to shift the risk of rising generation costs from the consumer to those who would understand the business best: the independent power producers and the financial institutions that backed them.

The purpose of this assessment was to ascertain the manner in which NYSEG and RG&E are supporting the formation of a competitive wholesale market and whether, through its participation in the NYISO, its role has benefited its retail electric customers.

As the load serving entities, NYSEG and RG&E serve integral roles by assuring adequate transmission interconnections for reliable generation supply, distribution system support of distributed energy resources, and the investment in advanced technologies that expand the opportunities for retail consumers to achieve the benefits that competitive markets can provide.

Roughly half of a consumer's retail electric bill goes to cover the cost of electric production and wholesale market transactions. The success of a competitive wholesale electric market as structured in New York State requires that the load serving entities, such as NYSEG and RG&E, provide the planning, infrastructure and management of wholesale market responsibilities in a manner that fully enables retail customers to develop and execute both short- and long-term energy procurement and risk management practices. Whether it is a small residential customer who seeks to find a competent energy service provider that offers standardized procurement portfolios or a large industrial customer who wishes to develop its own portfolio of physical and financial transactions as well as a range of complementary initiatives such as demand response management, renewable resources and distributed generation investments, both NYSEG and RG&E need to provide the framework under which their consumers can attain a reasonable expectation of success.

NYSEG and RG&E's role is to provide the transmission and distribution infrastructure in an efficient and cost effective manner, so that retail customers can implement and achieve their own energy procurement strategy. Because this is an evolving process that reflects market changes directed by the New York Independent System Operator (NYISO), the New York Public Service Commission and the Federal Energy Regulatory Commission (FERC), as well as the technological advancements deployed under Smart Grid initiatives and RPS mandates, both companies should have by now institutionalized within their strategic planning processes very specific goals and objectives that address their identified strengths and weaknesses relative to their wholesale market responsibilities. Both short and long term tactical measures with direct linkage to capital and operational budgets should be highly transparent.

NYSEG and RG&E also continue to provide bundled electric delivery and supply services to those customers who have not chosen a competitive retail supplier[1]. The Companies' energy procurement, trading and risk management practices should similarly be well-managed, clearly documented and demonstrate a high degree of risk management protocols.

Other sections in this report will address with greater specificity issues directly impacting the wholesale market process. Chapter VIII, for example, reviews the Companies' energy procurement, trading and risk management practices which are critical to the support of retail access to competitive suppliers, and the advancement of the State's renewable portfolio standards. Chapter IV addresses the Companies' forecasting practices. Chapter VI, long range system planning, drives the Companies' transmission and distribution investments that should optimize the access of low cost generation and renewable resources to retail markets. Inadequate transmission capacity can result in increases in line losses, congestion, and reduced reliability. Inadequate transmission investments can also limit development of dispersed renewable generation and acerbate an already aging infrastructure.

A. Background

The NYISO is central to the assessment of Companies' performance relative to wholesale market issues. The NYISO manages the wholesale markets and is regulated by the FERC. The NYISO's responsibilities include:

- The operation of the statewide energy dispatch network
- The monitoring of the bulk transmission adequacy, security and reliability
- The operation of the day ahead and real time energy markets
- The centralized planning of transmission requirements
- The management of demand response, capacity and transmission congestion markets

[1] More than half of the companies' residential customers receive bundled electric service.

- The development and oversight of transmission tariffs
- Compliance with NERC/NPCC reliability and planning criteria.

The Companies, on the other hand, play a dual role as a participant and stakeholder of the NYISO and the associated wholesale market process. As the load serving entity (LSE), the Companies perform their traditional retail services by assuring electric delivery, customer service and billing and metering. At the customer's discretion, they can choose between a standard bundled rate for generation that is offered by the Companies, or select a competitive supplier. In either case, the Companies remain responsible for other customer care responsibilities. The Companies' interface with the NYISO as an LSE is its daily participation in energy and capacity markets, support of demand response programs and management of its TCC contracts which limit its customer's exposure to added congestion costs. The Companies must also participate in a number of NYISO operational committees and task forces that support the development of these market oriented programs. For example, the Companies participate in the Load Forecasting Task Force (LFTF) which is responsible for developing the following year's peak load forecast which is used to compute the forward prices of the installed capacity market.

The Companies' other role is that of a transmission owner (TO). Although, the NYISO manages the scheduling of generation flow into and throughout the integrated bulk power transmission network, it has no investment in the transmission networks themselves. The TO's responsibility is to maintain its transmission network, comply with all FERC/NERC/NPCC planning and design criteria and to serve as a backstop for network upgrades within their franchise area.

In assessing how the Companies have responded to the challenges of this emerging competitive wholesale market, the following primary issues were assessed:

- Consumer protection
- Access to competitive sources of supply
- Support for distributed generation and renewable resources
- Reflecting wholesale markets in the Companies' strategic plans.

In assessing the Companies' participation in the wholesale markets we also addressed the following issues in other sections of this report:

- How NYISO and FERC participation support infrastructure development
- Reliability of transmission system
- Capital and operating budgets
- Energy procurement, trading and risk management protocols; chief risk officer
- Trading desk
- Board of Directors involvement.

B. Findings

Ten criteria were considered as Liberty assessed the Companies' management and performance covering a range of wholesale market issues. Because NYSEG and RG&E are primarily public utilities that participate in both the retail and wholesale electric markets, each of the criteria were considered in greater detail in other sections of this report, namely:

- Forecasting

- System Planning
- Supply Procurement
- Capital and O&M Budgeting
- Corporate Mission, Objectives, Goals and Planning.

The following table references each criteria to the section(s) in which they were addressed:

Criteria	Referenced Section	Chapter
Criterion 1: Transmission access to suppliers	System Planning	VI
Criterion 2: Distributed Generation and Renewable Resources	System Planning	VI
Criterion 3: Strategic Planning	Corporate Mission, Objectives, Goals and Planning and System Planning	II, VI
Criterion 4: Capital & Operating Budgets	Capital and O&M Budgeting	X
Criterion 5: Energy Procurement and Risk Management Controls	Supply Procurement	VIII
Criterion 6: Board of Directors involvement	Corporate Mission, Objectives, Goals and Planning	II
Criterion 7: Energy Procurement and Risk Management Proficiency	Supply Procurement	VIII
Criterion 8: Participation in NYISO proceedings	System Planning	VI
Criterion 9: Support of renewables, demand side management and Smart Grid	System Planning and Forecasting	IV, VI
Criterion 10: Participation in FERC proceedings	System Planning	VI

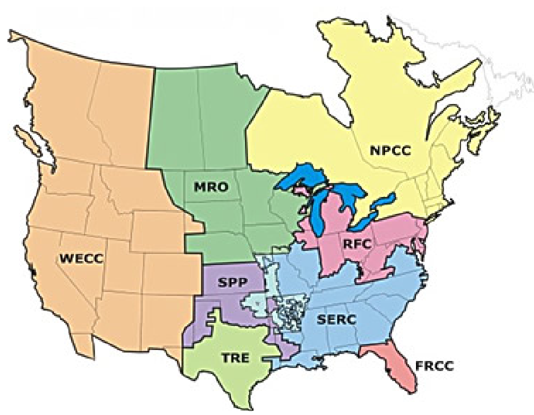
For our review of the wholesale market issues we further considered four subject areas that were considered determinative of the Companies' relative performance. Those areas included:

- Consumer protection
- Access to competitive sources of supply
- Support for distributed generation and renewable resources
- Reflecting wholesale markets in the Companies' strategic plans.

1. Consumer Protection

Our assessment of consumer protection centered on three interrelated and interdependent arenas:

- The Federal Energy Regulatory Commission (FERC) which regulates transmission access and tariffs, wholesale market monitoring, and system reliability.
- The New York Public Service Commission (NYPSC) which regulates retail electric tariffs, public utility oversight, consumer protection and administration of such public policy provisions as renewable portfolio standard, demand response programs and energy efficiency initiatives.
- The New York Independent System Operator (NYISO) which is responsible for managing the wholesale electric markets including transmission network, participation of independent power suppliers, and management of the real time energy markets among other responsibilities charged by FERC and the NYISO. The NYISO is also the conduit by which the North American Electric Reliability Corporation (NERC), who under the direction of FERC, is responsible for working with all stakeholders to develop standards for power system operation, monitoring those standards, assessing resource adequacy, and providing educational and training resources. Within NERC are eight regional entities that are directly represented by the regional transmission organizations and the transmission owners. The Companies, as well as the NYISO and the other TOs in the region belong to the Northeast Power Coordinating Council (NPCC) which implements the NERC policies and directives.



At the wholesale market level, the types of consumer protection issues that are most prevalent include:

- Transmission tariffs and open access
- Congestion management and exposure to uplift charges
- Capacity pricing
- Demand response markets
- Transmission network reliability.

In New York State, neither NYSEG nor RG&E typically stand alone as a participant and stakeholder in the formation of the competitive wholesale market in New York. As a transmission owner, the Companies' participation in FERC related proceedings is substantially managed via the New York Transmission Owners group which includes:

- Central Hudson Gas & Electric

- Consolidated Edison
- Long Island Power Authority
- National Grid
- New York Power Authority
- New York State Electric & Gas
- Orange & Rockland Utilities
- Rochester Gas & Electric.

As a result, the vast majority of wholesale market issues confronting the electric utilities in New York, especially as they relate to FERC Orders, NYISO initiatives, and NERC/NPCC reliability standards are coordinated through the New York Transmission Owners group.

We evaluated the Companies' contribution to consumer protection using three metrics:

- Positions taken by the Companies or supported by the Companies via the NY Transmission Owners group
- NYSEG and RG&E staff leadership positions serving the development of the NYISO
- Penalties paid for non-compliance to FERC, NERC or NYISO regulations.

In response to the first measure, we found that the Companies took a leadership position in the initial formation of the NYISO by chairing the New York power pool working groups leading to the development of the Locational Based Marginal Pricing (LBMP) market structure and ultimately the enabling documents establishing the New York ISO.

In summary, the Companies highlighted the following contributions they have made with regards to the protection of consumers via a reliable transmission and the efficient operation of energy markets:

- Actively participated in the FERC led mediation that developed the New York ISO shared governance model which expanded stakeholders to include consumer representatives.
- Filed complaint before FERC in 2000 which addressed a number of flaws in the energy and operating reserve markets. This effort resulted in authorizing changes in the market structure that among a number of elements included implementation of demand response programs and a more efficient day ahead and real time market.
- Championed efforts to improve New York ISO billing accuracy and reduce billing cycles resulting in improved market certainty.
- Involved in the development of market mitigation rules including the use of automated mitigation procedures for New York City markets.
- Championed planning and cost allocation provisions using the "beneficiaries pay" methodology.

The Companies have also supported a number of New York ISO initiatives via its direct representation on New York ISO committees or through the New York Transmission Owners group, including:

- Transmission congestion contract (TCC) markets
- Wind forecasting tools for day ahead and real time energy markets

- Small generator interconnection procedures
- Long-term transmission planning and response to FERC Order 890
- Interregional transmission planning and cost allocation in response to FERC Order 1000
- Comprehensive reliability plan, congestion assessment resource integration study (CARIS), and Smart Grid applications
- The Eastern Interconnection Planning Collaborative
- The Joint IS0/RTO Planning Committee
- New York State's electric utility transmission right-of-way management practices.

The Companies also point out that they were instrumental in the identification of the Lake Erie loop flow issue as well as prompting the New York ISO to use transmission load relief to reduce the financial impact of scheduling on New York's consumers. The NYISO calculated that the cost impact from scheduling these transactions to the market participants was about $95 million.

While it was important for the Companies to demonstrate support of a range of wholesale markets issues, we also assessed the active role that its professional and technical staff played in offering guidance and technical support in the development of the wholesale electric markets managed by the NYISO. We found a number of instances where the Companies have contributed to the NYISO via working groups, committees and operational task forces. Examples of their participation included:

- Participation on the New York TO executive committee
- Participation on the New York ISO governance process
- Member of the New York ISO Business Issues Committee (BIC), Operating Committee (OC), and Management Committee (MC). A company representative also chaired the BIC and MC. They also chaired the board selection subcommittee.
- Participation in such New York ISO working groups as the:
  - Market issues working group
  - Billing issues resolution team
  - Billing and price corrections task force
  - ICAP working group
  - Interconnections issues task force
  - Electric system planning working group
  - Market monitoring task force
- Chair of the NPCC Reliability Coordinating Committee
- Representation on the billing and accounting working group
- Representation on the Eastern interconnection planning collaborative and the interregional planning stakeholder advisory committee
- Participation on the New York ISO ICAP working group
- Chair and sub chair of the market participant audit advisory subcommittee
- Chair the market issues working group
- Participation in the SRC installed capacity subcommittee
- Participation in the New York ISO system operations advisory subcommittee
- Participation on the transmission planning advisory subcommittee
- Chair of the communications and data advisory subcommittee.

As a final measure, we reviewed the penalties paid by the Companies over the last five years for non-compliance to NYISO, NERC or FERC regulations. We assumed that this measure would provide some insight as to whether the Companies' actions coincided with its stated positions on wholesale market issues. Since 2007, the Companies have paid approximately $750,000 for 11 violations, although none were related to contract violations. Over half of the penalties ($450,000) are related to violations of NERC and NYPSC vegetation management requirements while two others totaling $267,000 related to installed capacity errors in the day ahead markets. Our assessment found no substantive penalties that would suggest that the Companies' performance before the NYISO was contradicted by either the magnitude or nature of the penalties imposed on the Companies.

In reviewing the Companies' activities before the FERC, NYISO and the NPCC, we identified two concerns. First, with the professional staff reductions experienced over the last several years, the numbers of experienced staff that can be allocated to the full and active participation in wholesale market issues has severely dwindled. We observed in the System Planning assessment how the transmission planning staff has shrunk from approximately 20 engineers to four, and that includes the section manager and an engineer in training.

Second, we observed, that given the extent to which the Companies have committed their resources to these activities, including leadership roles, there is no centralized management process by which these limited resources are allocated based on time commitment, priority or competing needs. At best, it appears as if the role that the Companies currently play are a vintage from the days when they had more adequate resources, or at worst, ad hoc without direction and purpose. While the Companies should be applauded for the historic role that they have played in supporting the development of wholesale markets in New York, we firmly believe that this highly important function needs to be closely monitored and controlled by management especially when one considers the diminishing technical resources remaining within the Company.

2. Access to Competitive Sources of Supply

The Companies are substantially in the business of transmission and distribution services. In short, with over 80 percent of their assets dedicated to T&D, it behooves the company to offer those services to an expanding market. The Companies have three basic transmission consumers: the retail customers or end users, the competitive energy suppliers and thoroughfare users who rely upon the bulk transmission network to transport electricity from one region to another. For the most part, the Companies have divested their interest in generation and as such have no incentive to limit access to competitive suppliers. In fact, Iberdrola is a major competitive supplier as a developer of wind generation in New York.

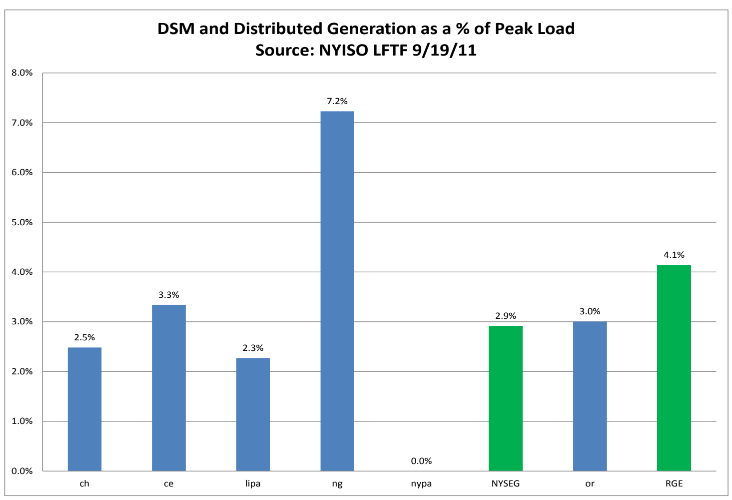
Our review found no particular pattern of neglect by the Companies as to failure to provide transmission access to competitive generation suppliers. If there is any issue of concern, it relates to the transmission congestion experienced in the southeastern portion of the State accessing the downstate region of New York City and Long Island. However, this is not an issue affecting either NYSEG or RG&E.

Furthermore, it is the role of the NYISO to evaluate transmission system requirements including the need to interconnect new generation. In compliance to FERC Order 890, each transmission owner must file its long range transmission plan. These plans are open to stakeholder review and the opportunity to participate in the development of any of the cited transmission requirements. The TO now serves as a backstop to develop such enhancements should no other party step forward.

3. Support for Distributed Generation and Other Renewable Resources

As a transmission and distribution operation, the Companies are prohibited from investing in fossil-fueled generation. In support of the wholesale market in conjunction with New York's aggressive Renewable Portfolio Standard,[2] the Companies provide the basic infrastructure for these resources to succeed. For small scale distributed resources, the Companies should provide clear and precise technical information as to distributed generators' responsibilities and costs to interconnect into the Companies' distribution network. For larger renewable projects, such as wind generation, the Companies must provide timely and accurate assessments of transmission extension requirements.

In general, we found that the distribution and transmission planning guidelines provided such information. While there were recommendations offered in the Electric System Planning section to improve both documents, we did not find any impediments to the development of distributed generation and other renewable resources. The chart below compares the Companies' customer participation in the NYISO demand response and distributed generation markets. Except for National Grid (NG), both NYSEG and RG&E are on par with the other utilities in New York.



4. Wholesale Market Strategic Planning

We observed that the Companies have not considered the rapidly expanding transmission planning demands within the context of the Companies' overall strategic plan. For example,

[2] 30% of electric production from renewable resources by 2015

FERC Orders 890 and 1000 expand the role of the local transmission owner to assess a far wider range of wholesale and retail market issues such as the impact of demand response on transmission needs or contiguous system transmission planning requirements.

The pendulum once shifted away from TO specific transmission planning to regional planning through the NPCC and the NYISO, but is potentially swinging back to the province of the transmission owners. This is not a certainty, as many of the FERC initiated issues have yet to be resolved. However, it is within the context of this uncertainty that the Companies have failed to consider how they need to be positioned to either influence or respond to these uncertainties in the most effective manner.

While the Companies have performed their transmission planning assessments in compliance to FERC Order 890, we found their long range transmission planning report to the NYISO somewhat sterile and absent any assessment of market uncertainty or risk of failure. We noted in the Electric System Planning section that other filings by other TOs did attempt to address these wholesale market issues and we referenced the Consolidated Edison Long Range Transmission Plan as an example. Throughout the performance of this management audit, we uncovered a number of nuances in the depths of FERC Orders 890 and 1000 that raised significant uncertainty to the ways and means that transmission owners must assess their transmission plans. For example, we noted that FERC has redefined the bulk transmission network to include systems above 100 kv as opposed to 230 kv. This means that the Companies, whose system is primarily below 230 kv, would now be responsible to perform transmission system studies, which are more numerous and far more complex. We found that FERC 1000 could be interpreted as requiring TOs to assess the impacts and uncertainties of demand management on their transmission plans and also perform more in-depth systems analysis with neighboring transmission systems. Yet, what we did not find was the Companies' strategic assessment of how these emerging issues accompanied by the risk and uncertainty they presented could affect customers via either higher rates, reduced reliability or diminished customer care. Nor did we find a strategic assessment of the Companies' strengths or weaknesses as they confront these uncertainties and what tactical measures would be needed to either maximize potential opportunities or mitigate risk exposure.

Liberty reviewed a recently published report by NERC entitled the 2011 Long-Range Reliability Assessment released in November 2011. This is a very impressive adoption of risk and uncertainty analysis as the cornerstone to long range transmission planning. This study addresses such issues as:

- Environmental regulations and impacts to bulk power system reliability
- Integration of variable generation from a system operations perspective
- Load forecasting uncertainty
- System modeling improvements.

The Companies should use this report as a guide to future transmission planning studies.

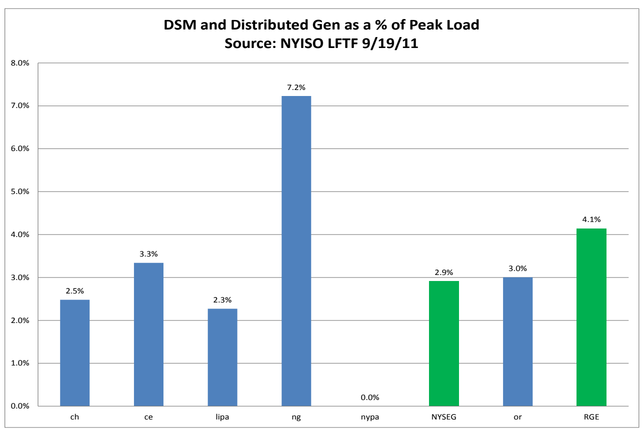
C. Conclusions

1. **The transmission network is maintained in such a fashion to meet the reliability needs for the delivery of electric supplies to all customers served by NYSEG and RG&E. Furthermore, the transmission network does support access to a range of competitive suppliers to sustain New York's competitive wholesale market.**

NYSEG and RG&E are transmission owners and major stakeholders in the NYISO. All evidence supports a finding that the Companies are actively involved at the NYISO and have developed its transmission network in a manner that supports the opportunity for access to competitive suppliers.

2. **The distribution network is maintained as required to support the installation and operation of distributed energy resources including distributed generation systems and such renewable resources as solar electric storage and wind generation.**

The Company's distribution planning process provides reasonable review and assessment of distributed generation and demand management initiatives. The following graph demonstrates that NYSEG and RG&E have supported demand side management at or above the same percent of peak load as other utilities in the state.



3. **The Companies' strategic plans do not address the dynamics of the wholesale market and specifically identify goals and objectives that will support the needs of their retail customers in the wholesale supply and delivery of electricity.** *(Recommendation #1)*

Currently, the Companies do not have a strategic plan that addresses any of the dynamics of the wholesale market. The Companies' Energy Supply/Transmission Services Strategic Plan, does offer a very high level assessment of risk and uncertainty, that identifies such threats as "Load Uncertainty" or the need to "replace/augment aging infrastructure (STARS)." However, this plan is but an outline, not an assessment. As a result, it is unclear how the various components of the wholesale market – mitigation of transmission constraints and access to low cost generation, achievement of RPS goals, and Smart Grid advancements in automation and load management, to name a few are factored in to the Companies long range plan. The 2011 Long-Term Reliability Assessment (11/2011) prepared by NERC was referenced as an outstanding example of a long range needs assessment of the United States' transmission requirements.

4. The Companies' capital and operating budgets do not demonstrate a direct linkage between each major line item and a specific strategic objective identified in the strategic plans.

While there is not direct linkage to a strategic plan, the capital budget does identify specific strategic goals and objectives in support of specific transmission projects.

5. The Board of Directors have not enumerated its commitment to wholesale competitive markets as demonstrated by a continuum of communications that support investments in the Companies' generation interconnection, and Smart Grid technologies, as well as other measures that protect the short and long term interests of its core customers.

The Companies have demonstrated an ongoing interest in Smart Grid technologies although its application to the US DOE was not approved, the Companies have prepared a Smart Grid strategy and now plan to use information and intelligence gained from the DOE approved project in Central Maine. As far as generation interconnections go, from a transmission perspective the Companies actively participate and comply with New York ISO procedures and FERC regulations that provide open access to the New York bulk transmission network. Relative to distributed generation, the Company does not have a well-defined strategy; however, the distribution planning process does provide for support consideration of distributed generation.

6. The Companies' energy procurement and trading desk is managed by a team of competent procurement specialists who abide by a strict code of conduct and comply with all business and regulatory standards.

The management team overseeing the gas and electric trading desk was professional and hands-on, and for the most part, the staff on the trading floor followed strict procedures and appeared well-trained and competent. Section VII Supply Procurement -Electric explores this issue in greater detail.

7. The Companies have demonstrated active participation in those NYISO proceedings that can affect the short and long term interests of its retail customers.

The Companies clearly demonstrate their participation and support of the New York ISO and provided positions taken that support the interests of retail customers over both the short and longterm.

8. The Companies were able to demonstrate how their participation supports the development of a more robust and efficient energy infrastructure via the support of Smart Grid technologies, renewable resources and demand side management programs.

The Companies developed a comprehensive multi-year, multi-phased strategy for the introduction and development of Smart Grid technologies which failed to receive the financial backing of the United States DOE. However, the Companies have received DOE and NYSERDA funding for projects such as Compressed Air Energy Storage (CAES) project. Additionally, over 400 megawatts of wind generation have been added to the system within the Companies' service territory.

9. **Emerging regulations and transmission planning requirements will significantly increase the demand for participation and support before FERC, the NYISO and NERC at a time when the Companies have experienced diminishing resources.** *(Recommendation #2)*

The Companies have provided evidence that they have actively participated in FERC proceedings although much of their participation has been through the New York Transmission Owners group.

The Companies have clearly demonstrated their participation and support of the New York ISO, and demonstrated positions taken that support the interests of retail customers over both the short and long term. However, coordination of NYISO/FERC and NERC participation has been ad hoc with responsibilities assumed or inherited. While it appears that the Companies have been well represented up until now, the expanding requirements for system security and reliability require a more strategic approach that is both vetted and approved by senior management. Furthermore, with past professional staff down-sizing and incentive retirements, the Companies have lost a wealth of experience and institutional knowledge. The Companies' participation and advocacy of emerging complex regulations and compliance standards will continue to expand which means that its current internal resources need to be continuously assessed and orchestrated as to development of corporate positions, compliance monitoring, participation and leadership in industry organizations and internal resource management.

D. Recommendations

1. **The Companies should prepare a strategic assessment focused on wholesale market goals and objectives.** *(Conclusion #3)*

This document should serve as a blueprint of the Companies' critical strengths, weaknesses, opportunities and threats and how management plans to either mitigate adverse risks or position themselves to take advantage of emerging opportunities on behalf of New York consumers. Given the uncertainty that these Companies face, this document should be regularly updated.

As a note of clarification, it is not suggested that the Companies have not considered some or all of these matters separately, but it does not appear as if they have, in a comprehensive manner, evaluated their transmission needs given the uncertainties of the wholesale market, regulatory initiatives, load uncertainty, economic recovery, emerging technologies and environmental concerns to name a few.

It is not our recommendation to replicate the NERC report referenced above, but rather to consider the analytic and intellectual detail invested in this effort to identify and assess risks and uncertainties this industry faces.

Examples of such risks might include:

- Ability for consumers to access low cost generation
- Capability of overhead transmission system to withstand worsening adverse weather patterns
- Advancements in cyber sabotage on network controls and protection devices

- Failure of the Company to keep pace with advancements in Smart Grid applications
- In ability of the Company to complete transmission projects on time and within budget.

2. **The Companies should create a formal matrix management team to oversee and manage the Companies' participation in NYISO, FERC, NERC, NPCC, etc. proceedings and issue assessments.** *(Conclusion #9)*

Currently, the Companies employ a matrix organization style to manage their many business functions. The Companies' participation in wholesale market related regulatory proceedings similarly calls for the interaction and input from a range of internal resources as well as the coordination of a range of perspectives as emerging wholesale market regulations are vetted and positions formulated. In order to assure continuity and process control, a matrix team designed to oversee the Companies' participation in these matters would help mitigate inconstancies in positions taken by the Company, inadvertent failure to respond to positions that may have an adverse impact on the Company or its customers and to assure that the assignment of issue review is delegated to the appropriate professionals.

Long-Term System Planning – Electric

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VI. Long-Term System Planning - Electric

A. Background

The combined NYSEG and RG&E transmission and distribution systems contain over 5,600 miles of transmission and sub-transmission circuits, over 40,000 miles of distribution lines and some 593 T&D substations. The growth in electric consumption and demand on the combined systems has waned since the recession. Nevertheless, between replacement of aging infrastructure and the expected addition of 7,000 electric customers per year over the foreseeable future, the companies plan to invest over $1.8 billion in T&D capital investments for electric systems from 2011 through 2015.

If this were all that the T&D system planners had to address, it would be a challenge on its own merits. However, the role and responsibility of the companies is expected to increase substantially over the next few years. Such changes include:

- FERC directives to NERC and carried out by NPCC and NYISO to enhance bulk transmission reliability and security.
- FERC's redefinition of bulk transmission network to include 100kv and above. Historically, FERC defined the bulk transmission network as those circuits 230kv and above. The companies' transmission network is primarily 115kv and below (Although, NYSEG does own 534 miles of 345kv and 233 miles of 230 kv transmission). Thus, the companies have been exempt from planning for more rigorous contingency criteria established for the higher voltage bulk transmission network. In late 2010, FERC issued an order redefining the definition of a bulk transmission system to include 100 kv and above which would then require the companies to upgrade their planning criteria to consider the far more complex N-1-1 outage conditions. This Order directs the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, to revise its definition of the term "bulk electric system" to ensure that the definition encompasses all facilities necessary for operating an interconnected electric transmission network. While the FERC order anticipated an exception process to exclude networks that are not necessary for the operation of the bulk power system, the companies' planners must be able to demonstrate such exclusion based on specific criteria set by NERC.
- The continued assessment and implementation of Smart Grid technologies.
- Expansion of multi-regional transmission analysis as seams issues between the NYISO, ISO-NE and PJM are solved.
- Expansion of wind and solar energy throughout New York requiring greater emphasis on aggregation and current flow analysis.

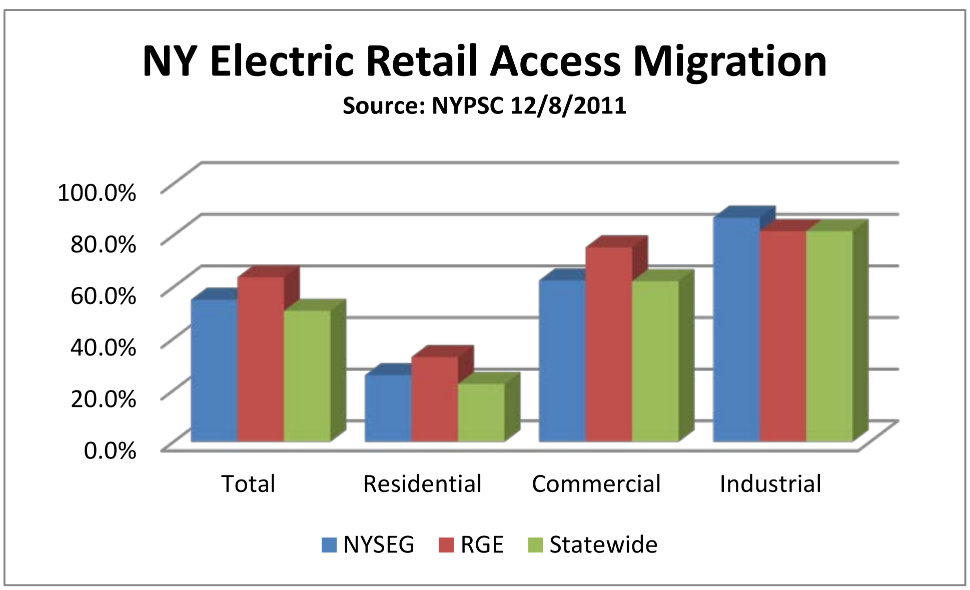
In meeting current and emerging responsibilities, we observed, with concern, the following:

1. The transmission planning section is understaffed.
2. There is an industry-wide shortage of trained power system engineers which limits the companies' ability to quickly hire new staff as the work load increases.
3. This shortage also places the companies at risk that one or more of their existing experienced staff could be recruited away.

4. Transmission planning has not retained outside consultants for a number of years which constrains potential outsourcing to firms low on the learning curve.
5. There is a significant leap in analytical requirements when performing N-1-1 dynamic analysis, vis-a-vis, N-1 and N-2 static or steady state analysis currently being performed by the companies' transmission planners.
6. The companies prepare no risk and uncertainty analysis. Plans are based on "best estimate" assessment of future needs, but fail to consider the impact of changing circumstances on T&D planning and implementation.

NYSEG and RG&E are for all practical purposes two transmission and distribution companies. Except for some limited amounts of generation and legacy purchase power agreements left after the formation of competitive wholesale markets in New York and the resultant divestiture of the bulk of their generating assets, the companies' core business is delivering electricity to franchised customers. Nearly 90 percent of assets are categorized as transmission and distribution plant in-service.

Some customers continue to subscribe to a fully bundled service whereby the Companies procure on the wholesale market energy and capacity on these customers' behalf. The Companies do not derive a return on investment for this service. However, most of the larger consuming customers, (*i.e.*, industrial and large commercial) as illustrated in the graph that follows, have chosen to procure their energy from competitive energy suppliers. In either instance, all electric customers located within the NYSEG and RG&E service area, regardless of where they procure the commodity of electricity, must receive delivery from either NYSEG or RG&E. The following table summarizes customer migration to third-party providers.



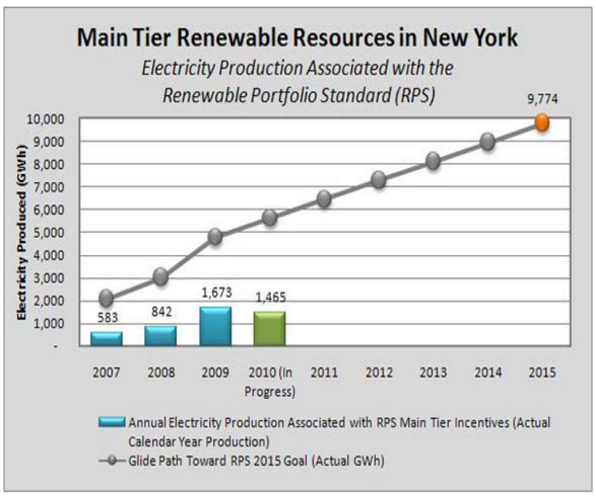
Electric reliability and access to low cost electric supply hinges on the Companies' ability to manage and maintain the transmission and distribution assets it already owns and to plan for and construct those networks that meet the future needs of their current and future customers.

The Companies are also responsible for supporting public policy and societal objectives. For example, New York State has enacted a very aggressive Renewable Portfolio Standard (RPS), which is managed by the New York State Energy Research and Development Authority (NYSERDA). New York's RPS is among the most aggressive in the United States, with a goal of obtaining 30 percent of its electricity from renewable sources by 2015 – referred to as 30 x15.

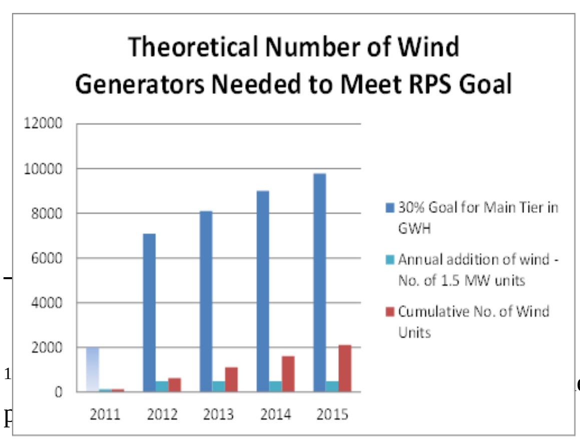
RPS energy targets for the 30 percent goal fall into three groups:

- Main Tier or Large Scale Generators - Large scaled generators that sell power to the wholesale grid or in some cases generate power for onsite use. Typically 1 – 2 MW wind generators
- Customer-Sited Tier - Small scaled generators such as a photovoltaic (PV) system on a residence
- Other Market Activities - Individuals and businesses that choose to pay a premium on their electricity bill to support renewable energy and state agencies that are subject to renewable energy purchasing requirements through similar policies.

The adjacent graph shows that Main Tier renewable resources will require substantial additional investment in order to accomplish the 2015 goal of 30 percent renewable generation resources. Commensurate with the planning for such dispersed generation will be the need to plan for substantially more transmission ties to the bulk transmission network. By 2015, some 8,000 GWH of additional Main Tier generation must be added out of a total goal of 9,774 GWH. Assuming most of this added generation is in the form of wind, some 3,000 MW of capacity or roughly 2,000 wind generators must be interconnected to the bulk power system.[1] (See the adjacent graph). While the location of this generation will be left to independent power suppliers, it is reasonable to assume that much of this added generation will be sited within the companies' service territory, requiring the system to be planned to accommodate it.



Renewable generation resources like wind are often dispersed, and necessitate a more flexible and responsive planning process to synchronize the development of those resources with a delivery system that can bring these desired products to market.



1 ... erator has a capacity of 1.5 MW and a capacity factor of 30
p...

The Companies also need to support statewide and regional efforts to develop a smart grid that employs advanced technologies that improve reliability, reduce losses, and have the flexibility to deliver electricity from a range of emerging technologies.

As transmission owners, the Companies also must serve the needs of the generation owners and operators that sell into the New York markets, by providing reliable access to the customer and assuring that their equipment is protected against frequency fluctuations, voltage swings and other power line disruptions.

The Companies must also address the reality that there are those who wish to harm our nation and that our transmission and distribution systems can be vulnerable to such attack whether physical or cyber. The companies also bear the responsibility to consider in their long range planning process how to build the next generation of delivery systems that can monitor, alarm and control such risks.

The Companies have been meeting their current planning obligations with a very small core of experienced distribution and transmission planners. A professional staff (transmission) that in combination approached twenty transmission planning engineers, has been whittled down to four – a manager, two seasoned transmission planners and a relatively new hire, in training. This reduced staff must prepare the transmission plans for 14 operational divisions, participate and support the NYISO's long range planning process, comply with NERC and NPCC and assess emerging regulatory changes flowing from the Federal Energy Regulatory Commission and the New York PSC.

We can appreciate the Companies' desire to minimize costs that could be passed on to consumers; nevertheless, it is also not good business practice to expose the Companies, their customers and generators, to the potential risk that inadequate system planning could adversely affect reliability, system protection, and congestion. Finally, there is reason to believe that this small core of system planners can neither continue to achieve the challenges the companies currently face as they deal with an aging infrastructure, nor can they step up to the added regulations that focus on network reliability and security, as well as the likely push by NYSERDA for more dispersed renewable generation in order to achieve the State's 30 percent RPS goal by 2015.

The companies have begun to develop strategic plans that address the needs of their transmission and distribution services business function. Unfortunately, it was difficult to envision how this core function, namely, system planning, would be able to provide the breadth of analysis and strategic insight to position the company to be a "world-class energy provider." We based our assessment of the companies' long term system planning on the following criteria:

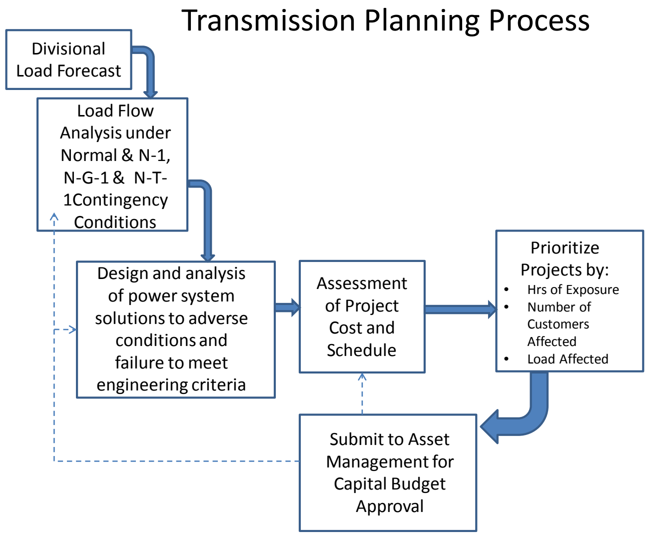
1. Long-term master plans should be in place; they should offer a credible strategy for how the system will evolve over an extended period, including expansion requirements, aging issues, reliability goals, growth of technology and other factors important to a long-term planning horizon.
2. Shorter term changes to the systems should be compatible with longer-term plans.

3. Strategies should be in place; they should describe how the systems will avoid over-extended lives for equipment and facilities, including an overall repair versus replace strategy.
4. Standard planning parameters should be published and updated as appropriate.
5. Guidelines for economic evaluations should be in place and uniformly applied.
6. Policies for weighting the benefits of non-financial attributes should be in place.
7. A system of prioritization of projects should be in place and uniformly applied.
8. Suitable investments should be made in defining new technologies that can be integrated into future system design or redesign of the existing system.
9. Optimum use of present technologies and the state-of-the-art should be an appropriate part of the planning processes.
10. NYSEG and RG&E should have a system planning staff with the appropriate quantity and quality of skills.
11. Non-traditional and innovative options should be considered in the planning processes.
12. The inputs to the planning processes should be credible and in a form and content compatible with the planners' needs.
13. Major projects should be specified by planners in a way that permits their subsequent design and installation to be optimally managed.
14. Standard decision-making rules for design options (*e.g.*, overhead versus underground) should be documented.
15. Planning processes, guidelines and standards should reflect regional differences where appropriate.
16. A structured approach to cost benefit analysis should be in place, with specific instructions for the handling of various financial and non-financial benefits.
17. Decision-making processes should consider risk, preferably in a quantitative way.
18. Mechanisms should be in place to provide planners with feedback on field results that should influence future decisions.
19. Ratings for equipment loading should be in place; they should reflect the operation expected and should be determined to maximize equipment use while maintaining equipment integrity.
20. Models, both static and dynamic, should be appropriate for the conditions simulated and their limitations understood by those that use them.

B. Findings

1. NYSEG and RG&E Transmission System Planning

System Planning is the engine that is fueled by the Companies' needs and then produces rational, engineering and economic solutions to those needs. The long range planning process begins with the development of a non-coincident peak load forecast for each of the 14 operational divisions. The peak load forecast is based on the highest actual peak load over the prior ten-year period and annually escalated by the implicit growth rate derived from that same historical trend line. It is not actually a load forecast, but more of a worst case scenario. The following chart outlines the primary steps taken to develop a long range transmission plan.



Because the NYSEG and RG&E transmission systems are below 230kv (generally 115kv and below), they have not been defined by the FERC as part of the statewide bulk power system and need only to comply with an N-1 outage contingency. This means that the transmission network must be designed to meet all engineering criteria under normal and single failure operating conditions. This definition will soon be changing as FERC has reduced the threshold voltage level to 100kv or above which would require the companies to design their systems to meet N-2 and N-1-1[2] outage contingencies.

Having a ten-year load forecast, load flow analysis is performed to determine what elements of the transmission network exceed thermal and voltage limits. Once the problems have been identified, alternative system reinforcements are determined to solve the system limitations. The alternatives are then evaluated against each other from a cost and system benefits standpoint. Based on this power systems analysis, remedial measures are evaluated. Such measures might include the addition of a substation transformer bank or the upgrade of a 69kv circuit to 115kv.

After establishing a set of remediation projects, the estimated cost and schedule of each is derived. The Companies then compute a relative priority rating by considering the projected size and duration of an outage and the number of customers affected. This list of transmission projects is then submitted to Asset Management for review and capital budget approval. The companies claim that this planning process is iterative, with feedback loops at each stage. This exercise forms the basis for the companies' commitment to over $300 million of electric investment per year. For the 2011 – 2013 periods, the predominance of capital projects (between 70 percent and 85percent) comports to the Appendix L agreement with the PSC. The next table shows projected expenditures.

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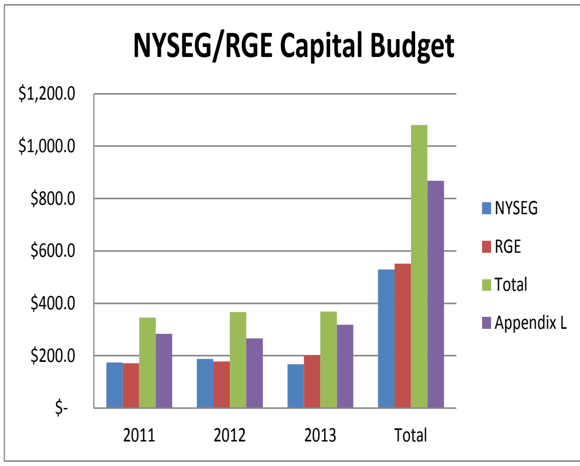
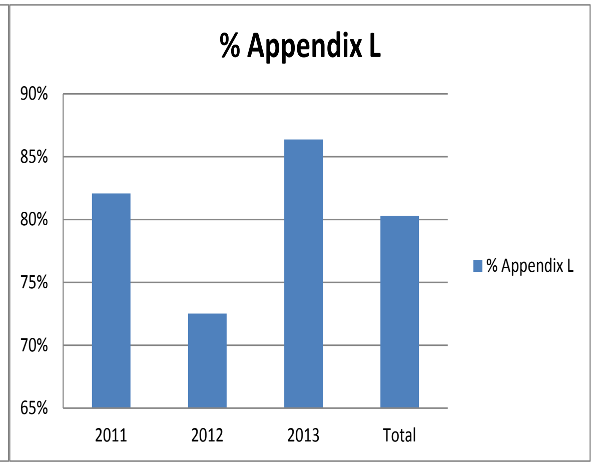
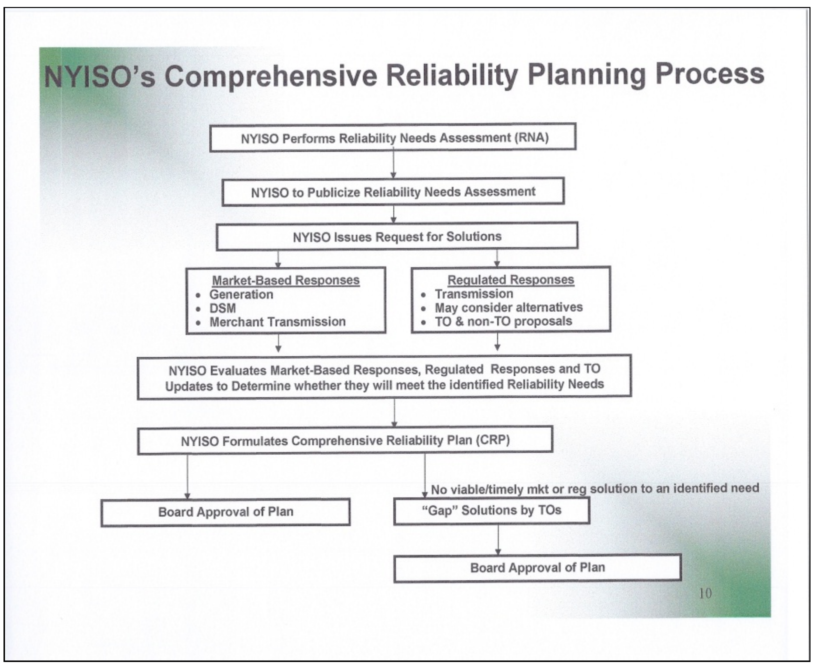
[2] N-2 contingencies assumes two simultaneous events, while N-1-1 assumes two non-simultaneous events with adequate time between them for manual operator action.





Many of the long-range transmission planning procedures have shifted from the internal prowess of the Companies' own transmission and distribution planners and engineers to a more centralized and transparent process managed by the NYISO, regulated by FERC (Order 890: System Long Range Development Plan) and directed by NERC (North American Reliability Council) and the NPCC (Northeast Power Coordinating Council). The NYISO posts on its web site both NYSEG and RG&E long range transmission plans and planning criteria.[3] Many stakeholders participate in the NYISO process and all are free to critique the Companies' transmission plan (see following chart for NYISO Comprehensive Reliability Planning Process).



[3] See www.nyiso.com/public/markets_operations/services/planning/process/ltpp/index.jsp

The New York transmission system represents an aging infrastructure. Both the NYISO and the companies have begun to evaluate measures to upgrade components of the network that are becoming obsolete. The STARS[4] initiative was initiated by NYSEG and RG&E and is now sponsored by the Traansmission Owners (TOs). Internally, the Companies have intiated their own version labeled TDIRP for Transmission & Distribution Infrastructure Replacement Program which focuses more on regional tranmission, sub-transmission and distribution aging infrastructure issues. The bulk of the Companies' current T&D capital budgets focus on such remedial action.

As addressed above, the structure of the transmission-planning process is consistent with conventional utility system planning practices:

- The transmission planning staff is experienced and trained to perform power systems analysis.
- The analytical tools used by the Companies are the same used by most other major electric utilities in the United States.
- The criteria used to assess and prioritize transmission, sub transmission and substation requirements is consistent with sound engineering practices.
- The Companies are in compliance with current state and federal transmission planning regulations and procedures (FERC/NERC/NPCC/NYISO/NYPSC).

However, the Companies may be ill prepared to step up to the emerging and expanding transmission planning and reliability requirements that have been described above.

Missing from all of the Companies' transmission planning documents is a long-term, strategic assessment of system requirements cognizant of the uncertainties and risks that these two transmission Companies face. The wholesale electric market is in flux as FERC focuses on broader regional integration, enhancements in system reliability and security, and assurance that dispersed renewable generation can reach its intended market. Furthermore, as we slowly recover from a problematic economic setback, uncertainties of investment, job growth, housing starts and ultimately electric sales and load growth, compound the complexity of transmission planning. The broader issue of wholesale markets will be reviewed in greater detail in Chapter V; the key point here is that the Companies do not consider uncertainty, either qualitatively or quantitatively, in assessing of its transmission system needs.

We found that the transmission plans as filed per the NYISO's Comprehensive System Planning Process (CSPP) do provide long range transmission system plans with a brief discussion on methods and criteria; however, neither of the plans, *i.e.*, for NYSEG and RG&E, provide an assessment of those factors that expose the long range plans to uncertainty and risk. Comparing the Consolidated Edison Long Range Transmission Plan[5] submitted to the same NYISO process in September 2011, illustrates a plan that assesses factors that can affect long-range transmission plans. While quality of content should supersede quantity, there is something to be said about the

[4] STARS: State Transmission Assessment & Reliability Study
[5] http://www.coned.com/tp/Long%20Range%20Plan.pdf

detail when comparing the NYSEG and RG&E seven page filings versus Con Edison's 57 page report.

An even more impressive adoption of risk and uncertainty analysis as the cornerstone to long range transmission planning is the 2011 Long-Range Reliability Assessment prepared by NERC and released in November 2011. This long range plan addresses such issues as:

- Environmental regulations and impacts to bulk power system reliability
- Integration of variable generation from a system operations perspective
- Load forecasting uncertainty
- System modeling improvements.

Many of the key assumptions that go into the companies' long-range transmission plan go unchallenged as to their degree of certainty and to what extent the long range plans are at risk – risk of either over-investment adding unnecessary customer costs or risks of under-investment lowering transmission reliability.

2. NYSEG and RG&E Distribution System Planning

Electric distribution planning, in contrast to transmission planning, comprises a shorter term process (*i.e.*, annual) to identify the more immediate needs of the two electric distribution systems including:

- Growth in electric demand including the addition of new customers
- Reliability engineering and system protection
- Voltage and harmonic regulation
- System disturbances (flicker)
- Distributed and backup generation
- Economic development

The design and operation of the electric distribution system falls within the management of two internal organizations:

- Engineering and asset management
- Electric operations

Distribution Engineering, which falls within the Engineering and Asset Management group, is responsible for distribution planning and field engineering. Electric Distribution (NY) falls within the Electric Operations group and is responsible for emergency response, distribution O&M, and distribution design. Together, these two groups identify and design distribution system requirements.

The criteria used to evaluate and design the companies' distribution network are outlined in a document entitled "TeamNY Electric Distribution Planning Guidelines". This document was prepared by the Distribution Planning Department for its internal use; it has not been sanctioned or approved by senior management. It is unclear as to why this internal procedural manual was neither approved nor sanctioned by senior management.

Distribution Planning operates substantially as a field operation where distribution engineers and operation and maintenance crews are situated close to the geographic regions they manage.

Annual studies are performed to identify potential distribution problems; however, the real time monitoring of the network and compliance to operational criteria and engineering standards set forth in the Electric Distribution Planning Guidelines define the ongoing assessment of the distribution system plan.

The companies rely on three software tools including:

- CYMDIST – A distribution planning and power systems tool offered by Cooper Power Systems. This tool provides the companies with the following capabilities:
  - Power flow and voltage drop analysis
  - Fault flow analysis
  - Optimal capacitor placement and sizing
  - Load balancing and load allocation/estimation
  - Voltage drop analysis with profiles
  - Harmonic analysis
  - Switching (tie-points) optimization
  - Network planning
  - Distributed generation modeling
  - Service restoration
  - Reliability analysis (predictive and historical)
  - Single contingency analysis with restoration
  - Substation and sub-network modeling
  - Secondary grid network analysis
  - Arc flash hazard assessment
  - Protective device coordination
- SynerGee Distribution - SynerGEE offered by GL Industry Services, can perform detailed load modeling and a host of useful analyses on radial, looped and mesh network systems comprised on multiple voltages and configurations.
- An in-house Excel spreadsheet used for regulator settings.

The TeamNY Electric Distribution Planning Guidelines provides a reasonable accounting of the companies‘ distribution planning criteria. What it fails to do is address such other criteria as:

- Overhead versus underground installation
- Application of distributed energy resources for load management
- Replacement of aging infrastructure
- Network automation applications
- Project prioritization and economic analysis.

The TeamNY Electric Distribution Planning Guidelines, as clearly stated in its introduction, are not officially sanction by the companies‘ senior managment. Furthermore, there does not appear to be a formal process by which changes in those guidelines are vetted by managment.

C. Conclusions

1. The Companies do not have a long-term master plan. *(Recommendation #1)*

There exists no clear strategy on how the system will evolve over an extended period. Although the Companies do produce a five-year capital expansion plan, which does address specific strategic goals as they relate to the prioritization of specific transmission projects, that is the closest they get to a long-term risk assessment. Absent from this analysis is a substantive assessment of what factors drive future plans (the load forecast is just one example), how certain those forecasts are, how that uncertainty affects the likelihood that the plan will be successful, and what mitigation measures can be taken to reduce or mitigate the risk of failure.

2. **The decision-making process does not consider risk in any measurable way, whether quantifiably or qualitatively.** *(Recommendation #1)*

The transmission-planning process does not include the assessment of forecast uncertainty. Relevant factors, such as peak-load forecast, customer migration patterns, weather trends, realizable load response and reliability of aging infrastructure present a degree of uncertainty as the Companies' prepare their ten-year transmission planning requirements. The greater the uncertainty, the greater is the risk that transmission plans will result in either over building (leading to higher costs), or under building, leading to declines in system reliability. Except for the fact that the transmission planners use the highest historical peak,[6] which serves as a surrogate for their "worst case" scenario, the planners do not assess what other drivers most influence the need for transmission investment, the degree to which each of these factors influence the outcome, and the likelihood that such forecasts are correct.

3. **The distribution planning guidelines are not approved by senior management, and there is no formal process for vetting and sanctioning any changes in design criteria.** *(Recommendation #2)*

The current distribution planning manual is an "unofficial" document that has not been approved or sanctioned by senior management, yet serves as the basis for analyzing and designing its distribution systems. There is also no process in place to uniformly consider or approve engineering design and performance criteria.

4. **The planning processes specifically reflect regional differences, as planning is performed on a divisional basis.**

T&D plans are designed for each of the 14 regional divisions of the two utilities. For the transmission plans, peak load forecasts are derived for each division.

5. **The transmission planning guidelines do not elaborate on the economic factors, assumptions and criteria for evaluating alternative solutions to identified transmission and sub transmission requirements.** *(Recommendation #3)*

Projects are prioritized by a uniformly weighted assessment of quantity of load and hours of exposure and the number of customers affected. However, the companies have not presented a rationale as to what level of impact drives the assignment of high to low priority.

[6] The peak load forecast is based on the highest peak that occurred over the prior ten year period.

6. **The prioritization process is uniformly applied; however, there is no clear understanding of how and why the parameters chosen establish the best rating system.** *(Recommendation #3)*

The prioritization of selected transmission projects was based on three criteria, namely, hours of exposure, customers affected, and megawatt loss of load. It appears as if projects were initially screened based on engineering requirements which also included assessments of alternatives that could produce the same or similar results.

7. **There is no structured approach to cost benefit analysis.** *(Recommendation #3)*

The prioritization of selected transmission projects was based on three criteria namely duration of hours of exposure, customers affected, and megawatt loss of load. It appeared as if projects were initially screened based on engineering requirements which also included assessments of alternatives that could produce the same or similar results.

8. **The transmission planning group uses the PTI PSS computer software for their evaluation of transmission upgrade requirements; the Company does not necessarily make the best use of the available features provided in this suite of analytical tools.** *(Recommendation #4)*

Furthermore, the company has no budget for consulting or training beyond the courses offered by PTI with regards to the PSS software tool.

9. **The adequacy of the quantity of experienced staff is questionable.** *(Recommendation #5)*

Experienced staff has over the years been reduced from about 18 planners to a manager, two experienced planners and a new member in-training. While the manager of transmission planning insists that this staffing level is adequate, it is difficult to see how reductions this drastic, coupled with emerging regulatory requirements relating to planning, reliability and system security, can be effectively managed without additional staff.

Further, a number of events could increase the workload of the transmission planning function. We found neither an urgency nor proactive engagement of management to consider how the Companies can be prepared to meet these challenges. Following is a listing of observations that we believe should have engaged an intensive assessment of the companies' planning requirements:

- Two electric utility systems, one radial, the other a network, with over 45,000 miles of T&D lines, nearly 600 substations and an annual capital budget of over $300 million a year for the foreseeable future.
- Load growth of nearly one percent a year with the expected addition of 7,000 new customers annually.
- An aging infrastructure being assessed under two separate study groups: TDERP (internal) and STARS (TOs) which will likely lead to additional upgrades and replacements.
- A FERC/NERC change in definition in bulk power networks that will expose the company to higher levels of system reliability and security design criteria.
- A New York State Renewable Portfolio Standard which is among the most aggressive in the nation calling for 30% renewable resources by 2015 that will drive the addition of

2,000 wind generators (3,000 MW) dispersed throughout the NYSEG franchise area requiring lateral feeds and bulk network enhancements.
- A transmission and distribution planning process focused on compliance to the Appendix L rate settlement with nearly 80% of the companies' combined capital budget through 2013 driven by this agreement.
- A transmission planning staff depleted from nearly 18-20 planners (including management), with each planner dedicated to the oversight of each of the companies' 14 divisions, to a total of four planners including the section manager and a recently hired engineer-in-training – two experienced planners covering seven divisions each.
- A transmission planning department with no budget for outside consultation or engineering support.
- A company that is insular from emerging best practice as it does not participate in any benchmarking programs that are focused on T&D practices, has no internal R&D program nor is a member of EPRI.
- No studies, reports or assessments that consider the risks and uncertainties that the company faces as to its ability to continue to meet its transmission and distribution responsibilities. This observation ranges from the technical assessment of future T&D plans, to anticipated changes in regulatory and public policy requirements to the companies' ability to perform these tasks with its current core of technical staff.

We found the planning staff to be experienced, skilled and well-motivated with a "we can get it done" attitude. The industry, however, faces an aging work force with a severe shortage of skilled power systems engineers.

> *According to a recent report by the U.S. Power and Energy Engineering Workforce Collaborative, about 45 percent of the engineers currently employed by the Nation's electric and natural gas utilities will be eligible for retirement over the next five years, creating a need for more than 7,000 engineers industry wide.*

We cannot predict with absolute accuracy how the issues discussed above will impact these Companies, we do find the position that they can "get it done" to be in stark contrast to our perception of what could be exponential growth in planning responsibilities.

System planning for a T&D company is the lynchpin to its capital expansion program and in meeting their fiduciary responsibility to provide safe, reliable electric service at just and reasonable rates. However, it goes farther than that – economic and reliable electric service drives the region's prosperity, environmental health and social welfare. There should be little tolerance for failure and as such in these uncertain times the companies, if they must error, it should be that they tried too hard, not too little or too late. Best management practices call for a more rigorous assessment of the companies' risk and uncertainty.

10. The Companies do not participate in any industry wide benchmarking or best practices programs. *(Recommendation #6)*

Such programs could help them learn what other leading utilities are doing and if and how they might achieve the same level of competency. The New York companies do not even "compare notes" with their counterparts in Maine.

D. Recommendations

1. Modify transmission planning process to include an assessment of risk and uncertainty. *(Conclusion #1 and #2)*

It would be preferable for the company to incorporate a quantitative analysis using such techniques as Monte Carlo modeling; however, as a minimum, qualitative assessment of critical input drivers, uncertainty associated with such drivers and potential impact on project performance should be performed.

As the Companies have not performed this type of analysis in prior assessments, it is recommended that the first year be a pilot study.

The transmission planning process does not consider the uncertainty associated with key input assumptions (drivers) in order to assess the risk that the project can be completed in time and within budgetary parameters. In fact, it does not appear as if IUSA identifies those input assumptions that have the highest correlation with expected outcomes, *i.e.*, performance achievement, scheduling and cost control.

The primary benefit associated with risk analysis is threefold:

- Identification and assessment of input drivers and forecast assumptions
- Analysis of impact of input assumption uncertainty on project risk
- Development of mitigation strategies to minimize risk

The NERC 2011 Long-Term Reliability Assessment was referenced as an example of the type of risk and uncertainty assessment envisioned.

2. Prepare a comprehensive distribution planning procedures manual. *(Conclusion #3)*

Many of the technical issues addressed in the Distribution Planning Guideline appear adequate, but the expanded procedures manual should specifically address such additional matters as:

- Reliability goals
- Asset management and aging targets
- Overhead versus underground criteria
- System automation objectives
- Cost benefit analysis and project prioritization process.

The current distribution planning manual is an "unofficial" document that has not been approved or sanctioned by senior management, yet serves as the basis for analyzing and designing its distribution systems. There is also no process in place to uniformly consider or approve engineering design and performance criteria.

3. Perform a reevaluation of transmission planning prioritization criteria. *(Conclusion #5, #6, #7)*

The Companies' guidelines provide for the analytical analysis of the transmission network based on a static load flow and stability analysis under normal and N -1, N-G-1 and N-T-1 conditions. Where system deficiencies are identified, IUSA then prioritizes the ordering of transmission projects based on three criteria: hours of exposure, number of customers at risk and load at risk. The three criteria are multiplied and the resultant product is used to prioritize the order in which the projects are completed: the higher the product, the higher the priority.[7]

This approach does provide some basis of establishing a relative ranking of proposed construction projects, but it fails to establish the foundation for assigning a project a high versus low priority. For example, at what level of load at risk drives a high priority and why? Or how many hours of exposure results in significant equipment damage? All that can be said of the current approach is that one project is rated higher than another when in fact all or none of them could either be high or low priority relative to system protection, outage management or customer impact.

The following table was developed for illustrative purposes only, but illustrates how the various criteria could be assembled. It is assumed that for each cell, a specific assessment is made to establish the magnitude of each criteria setting. Also, a fourth criterion was added, namely, the benefit/cost ratio, as a suggestion for other viable criteria to consider.

	Risk Criteria		
	Low	Medium	High
Hours of Exposure	8	16	24
Number of Customers at Risk	<25	<100	>100
Load at Risk	< 1 MW	<10MW	>10 MW
B/C Ratio	0.8	1	2

4. Retain a power systems engineering firm to perform an independent needs assessment of its transmission planning models and methods. *(Conclusion #8)*

The focus of this independent review should address, at a minimum, the following:

- Application of the PSS suite of analytical tools
- A review of the companies' transmission planning processes
- A review of the companies' transmission network and the data assumptions used to accurately represent each component in the PSS models
- Applications that the companies should consider as it evaluates compliance with NERC regulations.

[7] Note: this interpretation was claimed to be inaccurate during the December 9, 2011 CBA conference call. However, DR 786, Attachments 1 & 2 which are Excel spread sheets listing the 2011 – 2015 Transmission Project Planning metrics do indeed multiply the three criteria to establish a priority ranking.

The need to address the changing transmission planning requirements stemming from FERC's redefinition of the bulk transmission network has been discussed throughout this chapter. As defined by NERC, as a Transmission Planner, the companies would need to meet additional reliability standards. The primary transmission planner compliance responsibilities are system performance assessments and system modeling. System performance assessment standards include checking for exceeded voltage criteria limits, system equipment overloads, adequate stability, cascading outages, loss of load, and confirm transfer curtailments under a wide range of system operating conditions.

The transmission planning reliability standards call for the consideration of 30 operating conditions which are grouped into four categories. The acquirements associated with each of the applicable categories are contained in four separate NERC Transmission Planning Standards:

- Normal conditions (Standard TPL – 001 – 0)
- Single element contingencies (Standard TPL – 002 – 0)
- Multiple element contingencies (Standard TPL – 003 – 0)
- Extreme events (Standard TPL – 004 – 0).

The primary benefit derived from this recommendation is a professional and independent assessment of the mandatory NERC Reliability Standards as they apply to the companies, and what resources they will need to fully comply.

Based on this independent study, the company should develop a business plan outlining anticipated transmission planning requirements, resources required to comply with those requirements, and budgets needed to achieve the business plan.

The estimated cost for this recommendation is minimal when compared to the exposure the companies face against NERC non-compliance penalties alone. While recent monetary penalties issued by NERC ranged between $3,000 and $450,000 per event, the average penalty administered against some 24 organizations in February, 2011 averaged $48,000 which is roughly half the cost of this proposed recommendation.

5. Hire an additional experienced transmission planner. *(Conclusion #9)*

It is difficult at this juncture to estimate the actual number of additional transmission planners required to meet emerging regulations and compliance requirements, but IUSA should initially retain at least one additional experienced transmission planner to oversee and plan for compliance to the host of such new regulations. It is further noted, as an outcome of this assessment of regulatory compliance requirements, additional staff may be required.

Between NYSEG and RG&E there were approximately 18 transmission planners. Each planner was assigned responsibility to oversee the transmission planning for one of the 18 divisions structured by the companies. Prior to the Iberdrola acquisition, the former management reduced the number of transmission planners from 18 to 2. Part of the justification for this reduction was the transfer of some of the transmission planning requirements to the New York ISO and the gains in efficiency derived from more robust and comprehensive transmission planning analytical tools.

It is true that there had been a shift in planning analysis to the New York ISO, but in recent years there has been a focus on transmission reliability, security, and access of generation to broader regional needs. New regulations and compliance requirements by NERC, NPCC and FERC will likely begin to add additional responsibilities on the companies in terms of compliance, monitoring and planning. Furthermore, the emergence of new smart grid applications and the expansion of dispersed renewable generation will also require additional analysis and system design.

It is recommended that at least one additional transmission planner be added to the Transmission Planning section. Based on recent downsizing and early retirements, there may not exist such an individual with prerequisite skills, i.e., power systems engineering training, within the company and as such will need to be hired from the outside.

6. **Participate in one or more transmission and distribution benchmarking (best practices) programs.** *(Conclusion #10)*

The focus of participation should be oriented to technical solutions and best practices in transmission planning as opposed to the collection of comparative statistics and ranking of performance.

Over the last several years a significant number of experienced transmission planners have left the company and have not been replaced. Furthermore, due in part to budgetary constraints, the company has not participated in any utility sponsored benchmarking or best practices programs nor has it budget any funds for outside consultation from recognized experts in the field of transmission and distribution analysis and planning. It is apparent that the accumulation of loss of intellectual property has not been supplanted by either new hires or outsourcing. It is imperative that the companies move quickly to assure themselves that they have the resources and knowledge base to apply best practices in its assessment of transmission and distribution system plans. One such approach would be to participate in a recognized T&D oriented benchmarking program in order to share and learn from other first tier utilities.

There are at least two highly respected benchmarking programs that could be useful to the and inherently risky processes. These daily decision processes require regular auditing and vigilance, as they constitute one of the greatest areas of risk to the Company. Liberty believes that this function requires frequent and regular audits, in order to assure the most attractive electric sourcing and to look for any errors or malfeasance.

Gas System Planning

VII. Gas System Planning VII-1

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VII. Gas System Planning

System planning is one of the fundamental elements of the business, in this case the gas business. Key elements include:

- A long-term master plan for the system, which considers system expansion, aging of the system, reliability goals, growth of technology, and other factors important to long-term planning horizon
- A shorter-term plan link to the long-term plan
- An overall system strategy
- Standard planning parameters
- Planning processes, guidelines and standards
- Guidelines for economic evaluations
- Policies for weighting the benefits of non-financial attributes
- The system of prioritization of projects
- A system planning staff with appropriate skills capable of performing the function.

This aspect of the review was somewhat unconventional because Iberdrola does not have a system planning function for its gas business. Up until very recently, what passed for system planning was the annual capital budgeting process. With the last rate case, some additional planning emerged in that context. Without a plan or process, most of the standard criteria Liberty would apply to a review of gas system planning are inapplicable.

This chapter will address the components of system planning that take place at Iberdrola, identify the components that are lacking, and recommend that a process be put into place to address the shortcomings.

A. Background

Planning should reflect an integrated set of processes. Demand and use forecasting, resource planning, and system-operations planning are key elements of a properly integrated capital planning and budgeting program. Demand and use forecasting activities support many utility planning functions. Capital resource requirement plans build from long-term aggregate forecasts of use and peak demand growth. More localized forecasts (for example, numbers and type of customers, consumption and contribution to peak) support planning for extension of distribution systems. Forecasts of operations and maintenance needs and increased customer service requirements are used in the planning processes for personnel and support facilities. Effective planning also requires consideration of the effects of demand side management, energy efficiency, weather, and other developments.

Liberty identified the following general criteria to evaluate the Company’s gas system planning activities:

- Long-term master plans should be in place, addressing how the system will evolve over an extended period, including expansion requirements, aging issues, reliability goals, growth of technology, risk analysis and other factors important to a long-term planning horizon.

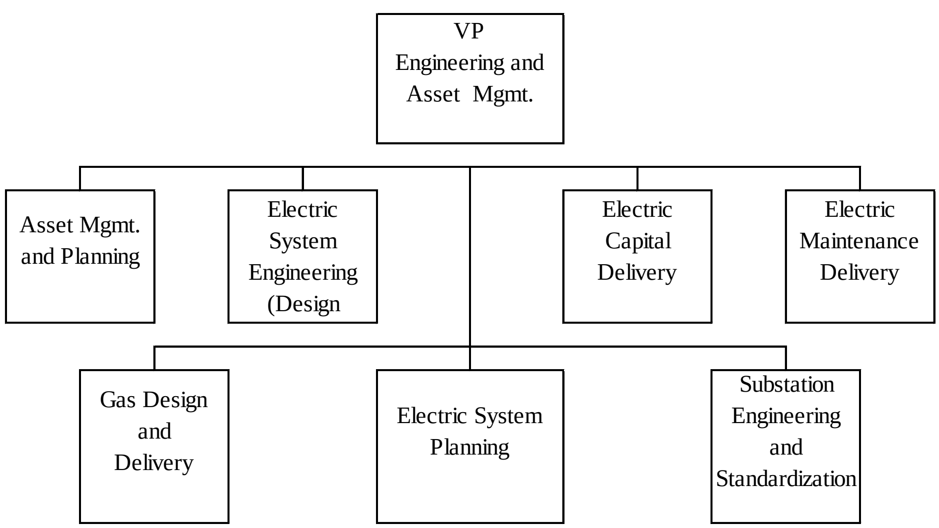
- The planning process should consider regulatory and legislative public policy initiatives, e.g., energy efficiency programs.
- Standard planning parameters should be published and updated as appropriate.
- Guidelines for economic evaluations and cost-benefit analyses should be in place and uniformly applied.
- A system of prioritization of projects should be in place and uniformly applied.
- Shorter-term changes to the systems should be compatible with longer-term plans.
- Planning processes, guidelines and standards should reflect regional differences where appropriate.
- Feedback mechanisms should be in place to provide planners with feedback on field results that should influence future decisions.
- The Companies should have a system planning staff with the appropriate quantity and quality of skills.

B. Findings

1. Organization and Staffing

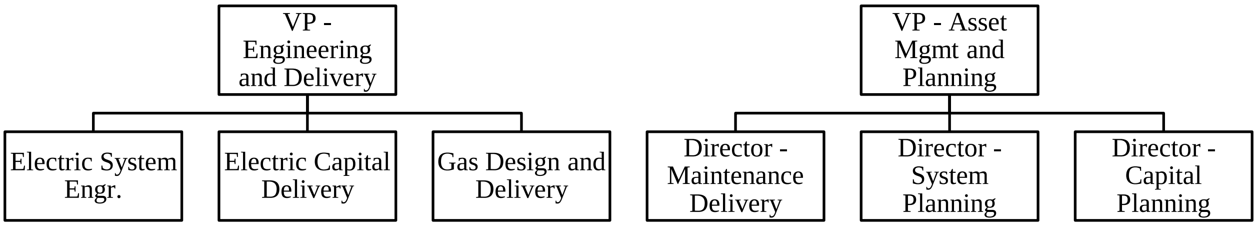
The organization structure involved in planning functions has been evolving over the course of the audit and has undergone significant change in both organizational location and personnel. At the start of the audit, the Engineering and Asset Management organization, where some of the gas planning functions were performed or coordinated, was configured as shown in the following chart.

Engineering and Asset Management Organization
February 2011



In July 2011, Iberdrola USA announced several organizational and personnel changes with the separation of the Engineering and Delivery and the Asset Management and Planning organizations as follows.

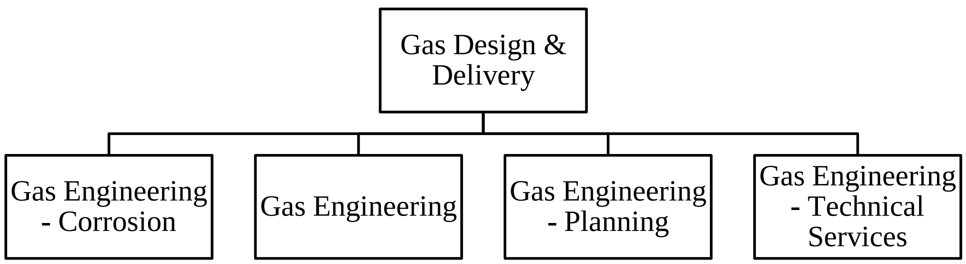
Engineering & Delivery and Asset Management and Planning Organizations
July 2011



The administrative role for developing gas capital projects remained with the Asset Management Group, with the Director of Capital Planning.

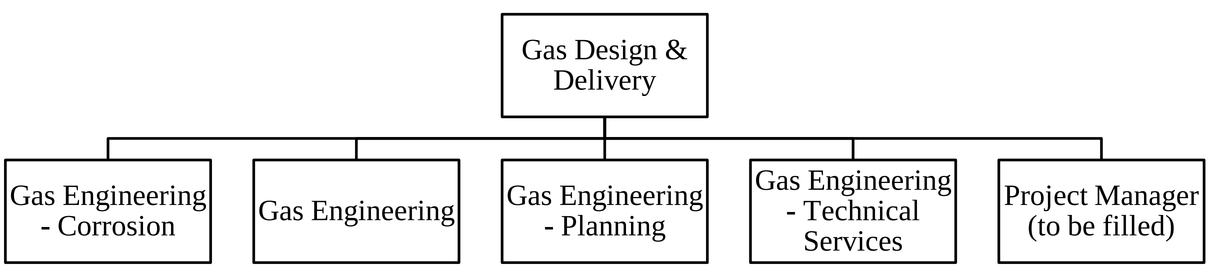
The Gas Design and Delivery group was unchanged with the July reorganization, and was configured as follows:

Gas Design and Delivery Organization - February 2011



With the retirement of the Director, Gas Design & Delivery in September 2011 and a new appointment to the position, that organization is currently undergoing a review and realignment, and a fifth position, that of Project Manager, was designated, which would reconfigure the organization as follows:

Gas Design and Delivery Organization - September 2011



2. Key Planning Parameters

There are many ways to characterize the key input parameters to a comprehensive gas system plan. For purposes of this analysis, Liberty has grouped them as follows:

- A long-term vision for the system, considering growth, changing demographics, changing customer class characteristics, and external events that may have a significant impact on the system
- A comprehensive plan for the replacement of vulnerable or leak-prone pipe
- Performance of mandatory activities, such as leak repair and relocations associated with municipal construction and maintenance activities
- System operational and safety upgrades
- Projected capital and O&M budgets for a future period, say five years, to operationalize the above inputs.

3. Iberdrola's Planning Process

The Company states that Gas System Planning prioritizes capital projects based on several factors, including:

- Regulatory requirements, such as the agreed upon replacement levels of leak-prone pipe in the last rate case
- Public improvement projects, such as to accommodate municipal projects which affect the LDC rights-of-way
- Need for infrastructure improvement, as determined by facilities condition and operating pressure
- Growth - customer driven, to satisfy tariff requirements
- Risk factors - age, leak history, probability of low operating pressure, and leak consequences.

The capital projects identified as a result of that process are input into the upcoming year's capital budget and moved to Gas Design and Engineering for design and construction.

Because Iberdrola is in a low growth environment, because a substantial number of large customers have left the system, and its load has been declining slightly, most of the Iberdrola system has adequate capacity. Planning for growth is a location-specific process typically involving new localized development or a major conversion project.

4. Distribution System Modeling

A key element of building, managing and monitoring performance of a gas distribution is the modeling function, a computer-based simulation of the entire system. Such a system enables simulations of various conditions on the system such as peak, average and light loads, system pressures at various points, effects of adding new loads, effects of shutting valves, changing pressures, and any other potential changes contemplated by the Company. The models can also be used in emergency situations when a specific section of the system must be isolated and all valve locations are not readily discernible.

Iberdrola uses the "Stoner" model, which is the de facto industry standard. The model had been in use at NYSEG integrated with their old mapping software system. The latter was converted to the new GIS system during the period 2007 to 2009, and the Stoner model is now being updated with the new GIS over a two-year period which began in early 2010. RG&E used an in-house model, GUIDE, up until 2008, when it converted to the Stoner system. Its models are being updated on a two-year schedule which started in July 2011. The models are currently maintained by the Gas Engineering - Planning staff in Gas Design and Delivery.

Ultimately, the models for both Companies are intended to be tied to the GIS system. NYSEG's GIS system is expected to be fully complete during the first quarter 2012, RG&E's in mid-2013. Subsequent to GIS completion, they will be integrated with the Stoner models.

5. The Gas Capital Spending Plan

In compliance with a Commission Order authorizing the acquisition of Energy East by Iberdrola, the Companies filed a Five Year Capital Investment Plan ("Plan") for their electrical and gas systems. The Five Year Plan:

> *...presents a comprehensive capital investment plan for the electric transmission, distribution and generation and the gas transmission and distribution business of NYSEG and RG&E for the period 2011 through 2015. This Plan positions NYSEG and RG&E to continue to provide safe and reliable service to customers.*

The Plan purports to *...help achieve the following strategic objectives of NYSEG and RG&E:*

- *Meet the electrical and natural gas needs of our customers*
- *Achieve best in class service reliability and quality*
- *Replace obsolete equipment and facilities*
- *Improve system effectiveness and efficiency through automation*
- *Sustain the environment*
- *Improve safety*

The gas portion of the Plan includes ongoing programs for the five-year period and one-time construction projects, four in 2011 and one each in 2012 and 2014. The table below shows the programs and projects included in the Plan, and the years in which expenditures for those programs will take place. Included in the table are the so-called *Appendix L* programs and projects. The bulk of the programs and projects, both ongoing and one-time, are indentified in Appendix L of the Commission's rate order dated September 21, 2010 ("Rate Order"), approved in the Companies' most recent rate case. See Appendix 1 to this chapter which provides a list and brief description of those projects not specifically described elsewhere in this report.

Programs and Projects Included in NYSEG and RG&E Five Year Plan

Program or Project	Appendix L	2011	2012	2013	2014	2015
Leak-Prone Main and Service Replacement	Included	x	x	x	x	x
Meter Purchase and Replacements	Included	x	x	x	x	x
Meters, Regulators and Gate Stations	Included	x	x	x	x	x
Government Related, e.g., Highway Relocations	Included	x	x	x	x	x
Allocated Share of Common Electric and Gas Facilities	Included	x	x	x	x	x
Seneca West Pipeline Interconnect	Included	x				
Canandaigua Cast Iron Replacement Program	No	x				
Southwest 60 (Lbs. Pressure) System Improvements	No	x				
Seneca Lake Storage Facility Control Equipment	Included	x				
Oakwood Avenue to Gardener Road (Elmira) Reinforcement	No		x			
Lansing Interconnect (Finger Lakes Area, Tompkins County)	No				x	
SCADA System Upgrade Project	Included	x				

Capital Expenditures 2011 - 2015

Program or Project	2011	2012	2013	2014	2015	Total
Ongoing Programs, listed in Appendix L	65,173	69,131	78,500	80,855	83,280	376,939
Seneca West Pipeline Interconnect	5,792	0	0	0	0	5,792
Canandaigua Cast Iron Replacement Program	1,035	0	0	0	0	1,035
Southwest 60 (Lbs. Pressure) System Improvements	3,460	0	0	0	0	3,460
Seneca Lake Storage Facility Control Equipment	1,851	0	0	0	0	1,851
Oakwood Avenue to Gardener Road (Elmira) Reinforcement	0	4,475	0	0	0	4,475
Lansing Interconnect (Finger Lakes Area, Tompkins County)	0	0	0	1,050	0	1,050
SCADA System Upgrade Project	2,279	0	0	0	0	2,279
Total	**79,590**	**73,606**	**78,500**	**81,905**	**83,280**	**396,881**

6. Replacing Leak-Prone Pipe

A concern throughout the gas industry is the condition of vulnerable older pipes, the most common of which are cast iron and unprotected bare steel. Every LDC should have a plan and program in place to address those types of pipes and to provide for their replacement.

Despite severe budget restrictions, the Company has persisted in its program to replace leak-prone pipe, attributable to its NYSEG heritage, which has since been extended to RG&E. NYSEG began eliminating its cast iron pipe in 1995 (300 - 400 miles) and completed that activity in 2011. Its emphasis has now shifted to the replacement of bare steel pipe. RG&E began eliminating its cast iron (approximately 200 miles) in 2003, is now down to approximately 80 miles, and is scheduled to complete that project in 10 years at current budgeted levels.

The Rate Order applies a number of performance measures related to gas safety and provides for reductions to earnings. The measures relate to:

- Replacement of leak-prone pipe
- Backlog of leaks
- Prevention of excavation damages
- Emergency response.

From a planning perspective, the relevant measures relate directly to pipe replacement and indirectly to backlog of leaks. The measures require NYSEG and RG&E to each replace a minimum of 24 miles of leak-prone main and 1,200 and 1,000 leak-prone services, respectively, per calendar year beginning in 2011 and continuing until changed by the Commission. They further require each Company to achieve a leak backlog of no greater than 100 leaks at year end.

Both Companies use the same internally developed algorithm to rank the leak-prone mains, which considers operating pressure, land use, distance from structures, surfaces (e.g., paved or unpaved), numbers of leaks, numbers of bare steel services attached to the main, and cost. RG&E had used a commercially-available program package in the past but changed over to the in-house algorithm because it was more specific to the needs of the Company and did not have the annual fees associated with the purchased package.

C. Conclusions

1. There is no formal or informal long-term planning process, vision or plan at the companies. *(Recommendation #1)*

With the exceptions of the replacement of leak-prone pipe and the two projects identified for the years 2012 and 2014, respectively, the Iberdrola companies do not perform the gas system planning function well and do not have a system plan beyond a one-year horizon. For the most part, it does not perform the types of activities identified in the Background section of this chapter.

The Companies do have a five year, 2011-2015 Capital Spending Plan, for both the electric and gas businesses, filed with the PSC on April 1, 2011, which was a document required as a condition of the approval of the acquisition by Iberdrola. The gas projects in that plan included two of those incorporated into the Rate Case Order in the last rate cases, 09-G-0716 and 0718. We also note that only two of the projects in the Capital Spending Plan extend beyond 2011. While Liberty does not take issue with the specific projects identified in the Rate Case Order and the Capital Spending Plan, we note that they are not a substitute for a long-term plan.

One element of long-term planning that is in place, although not labeled as such, is the Company's ongoing long-term plan for replacing leak-prone pipe, which is addressed in Conclusion #3 below.

2. **The organizational structure, including the recent reorganization and reassignment, is not conducive to long-term planning.** *(Recommendation #1, Chapter II Recommendation #2)*

No individual or group has the responsibility for long-term planning. The position identified on the organization charts as a planning position is responsible for a catch-all of functions, including: preparing the annual capital budget; maintaining and updating the models of the operating systems ("Stoner" models"); running those models to ensure there is sufficient supply for potential new customers as identified by marketing; tracking capital spending on "major" projects, typically defined as discrete projects over $1 million;[1] and developing and maintaining the relationships with local producers.

Several other factors contribute to the structural problems which tend to frustrate system planning:

- The gas engineering organization, the logical choice for a planning group as the organization is currently configured, is buried in an electric group, reporting to an electric manager with no gas experience.
- The gas organizations do not have good communications with each other. As mentioned in the Gas Supply Chapter, Gas Engineering has limited communications with Gas Supply.
- Those planning functions that are performed are fragmented in the organization.

An example of the fragmentation and poor communications is the design day criterion used by the Companies, a key element of performing both the gas supply and system planning functions. As described in Chapter IX, Supply Procurement - Gas, the Gas Supply group uses a design day, the coldest day the Company is prepared to handle, of 75 heating degree days (HDDs), based upon a study commissioned by NYSEG in 1992.[2] Gas Engineering states that it designs the system to a 70 HDD day, tied back to the same 1992 weather study. A further disconnect is that

[1] E.g., implementation of the SmartTrac system in Gas Supply, the SCADA upgrade in the Gas Control Center, the Southwest 60 and Seneca West Storage Interconnect projects, and a public school complex conversion to natural gas.
[2] Liberty believes that number is excessive and has recommended a weather study to examine it.

the load forecasting process has recently begun to use a 10 year historical period, as discussed in Chapter IV, Load Forecasting.

3. The companies have a well-developed plan for dealing with aging infrastructure, e.g., replacement of leak-prone pipe (cast iron and bare steel).

Despite severe budget restrictions, the Company has persisted in its program to replace leak-prone pipe, attributable to its NYSEG heritage, which has since been extended to RG&E. NYSEG began eliminating its cast iron pipe in 1995 (300 - 400 miles) and completed that activity in 2011. Its emphasis has now shifted to the replacement of bare steel pipe. RG&E began eliminating its cast iron (approximately 200 miles) in 2003, is now down to approximately 80 miles, and is scheduled to complete that project in 10 years at current budgeted levels.

The budget restrictions were so tight that up until the most recent rate cases, the only capital spending was dedicated to leak-prone pipe replacement and mandatory relocation work.

The replacement of leak-prone pipe replacement is a high priority for the PSC. Metrics for the program are included in the Commission order in the most recent rate case, and include the following:

Leak-Prone Pipe Performance Measures

Category	Target	Exposure
NYSEG		
• Leak-prone Main	24 miles	8 basis points
• Leak-prone Services	1,200 services	8 basis points
RG&E		
• Leak-prone Main	24 miles	8 basis points
• Leak-prone Services	1,000 services	8 basis points

The figures in the table above include main and service replacements in any context, including the leak-prone pipe replacement program, municipal projects, and leak or other repairs.

Iberdrola is a leader in the state in the replacement of leak-prone pipe on a system-wide basis. However, it did enjoy a substantial advantage over most other New York utilities in that its percentage of leak-prone main was much smaller than the other LDCs.

4. The companies perform annual planning as a component of the annual budgeting process.

The annual capital budgeting process typically begins during the summer for the construction season for the following year. In the May/June time frame, the Gas Planning group sends out, via e-mail, an internal budget call letter to the various division supervisors, requesting input as to required municipally-driven projects (e.g., highway relocations), recommended system reinforcement, and other recommended work.

The various proposals, as well as the input from the Gas Engineering - Corrosion group with respect to the leak-prone pipe replacement program, are then evaluated by the Manager of Gas

Planning, the Manager of Gas Engineering, the Director of Gas Design and Delivery, and possibly others and sent up the management ranks for review and approval.

The process is fairly informal, as there is no written policy or procedure; the timeline is not fixed, and there are no written criteria for project selection.

According to the Company, they have recently begun to look at a two-year planning horizon.

5. The Companies' system models are not up-to-date, which limits their accuracy and usefulness. *(Recommendation #1)*

The Companies use the Stoner system model, generally considered to be the industry standard model. NYSEG has utilized the Stoner model for many years, while RG&E migrated to that model from a home-grown model in 2008.

The GIS and Mapping groups build and update the models, based upon the corporate SAP system and databases, and then send them to Engineering for verification of loads and gas flows. The models must be updated regularly for changes in customer data, load data and other changes on the systems. NYSEG's regional models (by Division) and RG&E's models are out-of-date, having been last updated in 2009 and 2008, respectively, although some of the individual records are five or more years out-of-date.

Ultimately, the conceptual plan is to have the GIS database match the SAP records and be continuously updated, which will also update the Stoner model databases continuously. Then Engineering will run the Stoner models to examine pressures and gas flows annually. That practice had been followed in the past but was abandoned as a result of staffing limitations and the staleness of the data.

In Liberty's experience, common practice is to run the system models prior to the winter season to prepare for the winter, and after the winter season to analyze performance. However, any model can only be as good as the underlying databases, and the Companies' databases are out of date. Company personnel state that they do not do the annual review because the databases are stale, although they do examine specific areas where they are aware of low pressure issues. However, Liberty suspects that the underlying reason is the lack of available staff as much as anything else.

While the Company has a schedule to update NYSEG's models by mid-2012 and RG&E's by mid-2013, it is far from clear that the necessary plan and resources are in place to accomplish those tasks. Further, at this point there is nothing beyond a conceptual plan to integrate the models with the GIS system.

6. Iberdrola does not have a plan to upgrade its system monitoring and control capabilities. *(Recommendation #1)*

Chapter IX, Supply Procurement - Gas, explained the lack of sophistication of the Companies' SCADA capabilities, including the limitations of the Gas Control Center, the lack of remote control of the systems, with only a few minor exceptions, and the lack of redundancy of communications channels. The current SCADA upgrade project will bring the software platform up-to-date but will not address any of those other issues. The existing set of monitoring stations and sensors reflects an evolutionary process that has not been subjected to an overall study and evaluation to determine an optimal considering operational and safety and reliability conditions.

In contrast, on the electric side of the business, Iberdrola has a $7.8 million project under way, the [electric] Energy Control Center Project, to design and install a fully integrated Energy Management System / SCADA / Distribution Management System and Outage Management System (OMS) to provide ... *real time transmission, substation, and distribution situational awareness for OMS dispatchers and operators.*

7. Iberdrola has initiated a project team to examine business opportunities associated with Marcellus Shale and other formations.

The Company formed an integrated team in August 2010, the Marcellus Shale Opportunity Project (MSOP), to explore Marcellus Shale opportunities, including potential local production and development of Iberdrola-owned properties. The scope was subsequently expanded to include additional opportunities related to the Utica Shale and Trenton/Black River formations. The MSOP was chaired by the Risk Manager, with 15 members, including the following individuals or areas:

- Risk Management
- President of NYSEG and RG&E
- Regulatory
- Legal
- Gas Supply
- Strategic Sourcing
- Engineering
- Real Estate
- Environmental Compliance
- Gas Business Development

The MSOP team contacted 46 companies with an RFI to identify business opportunities related to Marcellus Shale in New York State. Ten companies responded, five positive and five negative. All five positive responses were from companies who already had existing relationships with NYSEG and RG&E. From a production standpoint, the team concluded that there is low interest in leasing in New York at least until the moratorium ends, that even absent the moratorium, the land area and configuration of the properties owned by NYSEG and RG&E may be too small to be of interest, and that joining coalitions could be an attractive alternative.

From a supply standpoint, the MSOP team concluded that the Company's market volumes are sizable enough to attract the interest of producers, that their service areas are positioned close to production areas and in the path of potential gathering systems or pipelines, and that the transportation infrastructure in New York, as it currently exists, would be limiting, perhaps to existing producers, until additional infrastructure is built.

As of March 2011, the MSOP team prepared a report and developed the following recommendations:

- *Continue the discussions on received proposals and implement identified business opportunities,*
- *Analyze the possibility of extending the service territory,*
- *Consult the PSC on the convenience of entering into long term price hedges,*
- *Monitor the evolution of the hydraulic fracturing moratorium in NY State,*
- *Limit access to mineral rights on new leases,*
- *Seek and join the right coalition/s to enhance acreage value,*
- *Follow up on infrastructure and upstream development,*
- *Keep monitoring business opportunities beyond the RFI process.*

Subsequent to the report, the team evolved into a weekly conference call, chaired by the Manager of Gas Supply, to discuss new developments relevant to its mission. Agendas have included the following topics:

- DEC activities, including hearings and announcements
- Media articles of interest
- Discussions with a supplier
- Marcellus Shale supply fromthe Empire Extension and Laser pipeline projects, and their impacts on the Companies.

8. The Company has not developed scenario or contingency plans for the impacts of Marcellus Shale (and potentially Utica Shale) on its gas supply despite the enormous potential and favorable positioning of some portions of the service territory. *(Recommendation #1)*

The future of hydraulic fracturing and exploitation of Marcellus Shale and other potential shale gas sources rests with the legislature and governor of New York State. Liberty considers the most likely outcome to be the permitting of drilling in many areas of the state, and a fairly rapid deployment of production assets (e.g., drilling rigs, gathering lines, and pipelines) to bring the gas to market. While Iberdrola represents a significant consumer market for gas in the aggregate, it is a geographically diversified service area with very few large gate stations, which would represent a small percentage of the total production.[3] Producers will want to deliver large volumes to the major pipelines.

The risk to the Companies is that the producers will bypass their systems because they do not represent significant markets and therefore not worth the bother. On the other hand, producers and transporters are aware of the advantages of obtaining local support and good will for their potential and ongoing activities, and tend to be open to considering and accommodating local issues if they are surfaced early in the process.

Therefore, it is incumbent upon Iberdrola to develop conceptual plans and scenarios for its system so that it is best positioned to tap into shale gas if and when development proceeds.

[3] For example, NYSEG and RG&E combined have some 80 gate stations, while the common facilities of Con Edison and National Grid which serve New York City have 8 gate stations.

D. Recommendations

1. Develop a gas system vision, master plan and associated implementation strategy, including designation of the responsible individual(s) and organizational unit(s). *(Conclusions #1, 2, 5, 6, 8, Chapter IX Conclusion #8)*

The Company should create a task force or committee to address this issue. It should include, as a minimum, representatives from Gas Supply, Gas Engineering and Planning, Gas Operations, and Load Forecasting. The initial phase should include development of a scope of work, a plan, prioritization and schedule of activities, over a six-month period, using existing resources, at no incremental cost. At that time, they should determine the level of effort to develop a Master Plan and whether and to what extent additional staffing or other resources (e.g., software) are necessary to develop a Master Plan addressing the types of issues identified in the Background section of this chapter.

The plan should be fairly specific for a five-year period, with a conceptual plan and vision looking out at least 10 years. One approach to development of such a plan is to prepare a vision for what the system should be in 10 and 20 years, and identify the actions and steps required to achieve that vision. Activities that should be included in the scope of the plan include:

- A comprehensive examination of its system to look for opportunities to interconnect with different pipelines to procure lower priced gas and to increase reliability
- Completion of the update of the Stoner models as quickly as possible, linking those models with the GIS system
- A review and evaluation of the monitoring stations, monitored parameters, and sensors on the gas systems, determination of whether additional points are required, whether additional telemetering should be added, and whether remote operable equipment (e.g., valves and regulators) should be added
- Development of conceptual plans for accessing Marcellus Shale gas if drilling and production of such gas is approved.

In addition to the above activities, where the bulk of the activities are front-loaded, planning activities should include the following ongoing activities:

- Periodic updating of the plans developed
- Continuing, timely updating of the Stoner models
- Identifying potential system improvements projects and developing conceptual estimates.

While Liberty is not recommending any additional staff at this time, in our experience an ongoing planning process might involve two full-time staff members. Their activities would include ongoing maintenance functions, such as updating the Stoner models, as well as planning studies.

Liberty notes that several of the underlying activities for a planning process are already in place, including the leak-prone pipe replacement program, the "pathing" analysis of the cost of gas delivered to the citygates via different pipeline routes, and the MSOP.

Chapter VII: Appendix 1

Summary of System Reinforcement and Upgrade Projects
Identified in the Five Year Capital Spending Plan

1. Seneca West Pipeline Interconnect to Elmira Distribution System - Construction of a five mile, 8" steel, 1,100 psig high pressure natural gas transmission pipeline and new meter and regulator station which would connect the Seneca Lake West Pipeline directly to NYSEG's Elmira gas distribution system.
2. Canandaigua Cast Iron Replacement - Replace approximately 1,300 feet of 4" and 1,000 feet of 6" cast iron gas main and approximately 200 feet of existing 6" bare steel gas main in conjunction with the road rebuilding of the downtown City of Canandaigua.
3. Southwest 60 System Improvements - Install 6 miles of 12” wrapped steel pipe and one new distribution regulator station, to improve the Southwest 60 PSI RG&E gas distribution system, which provides natural gas to the towns of Aon, Geneseo, Lakeville, Livonia, York, Perry and Mt. Morris.
4. Seneca Lake Storage Facility Equipment Replacement - Replace existing OPTO 22 Program Logic Control (PLC) Equipment with new Telvent PLC Equipment at NYSEG's Seneca Lake Storage Facility in Watkins Glen, NY.
5. Oakwood Avenue to Gardner Road point of delivery - Installation of new steel main in Elmira Division for system reliability and reinforcement.
6. Lansing Interconnect - System reinforcement project in to meet increased demand in the Lansing area.

Supply Procurement – Electric

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VIII. Supply Procurement - Electric

A. Background

Electric commodity prices have experienced significant price volatility in the past several years in New York. NYSEG and RG&E remain responsible for acquiring the electric supply for those customers who have not switched to retail supply competitors under the default supply option ("DSO/VPO"). This very substantial supply resource responsibility is estimated to be approximately [redacted] million MWh of energy and related hedging for NYSEG and [redacted] million MWh for RG&E DSO/VPO customers in 2012. The total dollars for these categories of electric supply acquisitions for the two companies is estimated to total about [redacted] million in 2012.

The two companies also have responsibility for purchasing capacity for the electric requirements of a large amount of their delivery customers. These incremental amounts are estimated to total approximately [redacted] MW for NYSEG and [redacted] MW for RG&E in 2012. Optimizing management of these electric supply requirements requires the use of a structured, comprehensive, and flexible approach to supply portfolio management to reduce price volatility and overall pricing levels. Portfolio management includes as primary components long-term portfolio design, resource acquisition, and risk management. The utility industry has undergone significant advancement in these disciplines during the past decade.

Setting comprehensive and specific objectives lays the cornerstone of effective management of energy procurement. Companies should adopt clear goals and objectives, and support them with portfolio analysis and planning, sound operations and effective physical and financial transactions. Without first specifying objectives to offer guidance and limits, a company is much less likely to design and manage a portfolio effectively. With respect to physical and financial hedging, it is also necessary to provide a clear definition of goals, transaction types, duration, counterparty qualification, and fuel-use targets. Goals and objectives should balance price minimization, volatility mitigation, and supply reliability. These areas of performance cannot be optimized independently; progress in one aspect may come at the expense of others. It is also important that the utility, its regulators, and stakeholders develop a mutual understanding of the preferred means to strike this balance.

Portfolio management includes the development of an electric portfolio design, the procurement of the resources identified in that design, and management of the resources on an ongoing basis. Effective portfolio planning and management provides utilities and their regulators with a systematic process for identifying and managing electric resources to produce reliable service at reasonable prices.

Managing procurement activities requires processes that are efficient, consider all available market alternatives, are conducted at arm's length, are transparent, and transacted consistently with program objectives. The need for strong processes and procedures, controls and oversight is critical. The control elements of the process include the oversight roles of management, risk management processes, auditing and the review of other organizations as appropriate.

The criteria by which Liberty evaluated electric supply procurement included the following:

- Portfolio design and management
  - A comprehensive, structured portfolio approach that derives from appropriate pricing, reliability, and volatility mitigation goals should guide supply procurement.
  - Clear goals should be established for the risk management and hedging programs, including specifically targets relating to minimizing rate impacts and market risk.
  - Program goals should be clearly communicated and mutual agreement established between the companies and the NYPSC.
  - Portfolio design should be continually evaluated for consistency with goals and objectives, desired results, and regulatory guidelines and requirements.
  - Portfolio design should incorporate the established objectives, expected results of, and uncertainties surrounding demand management and energy efficiency.
  - Portfolio design should incorporate the flexibility necessary to respond to other major uncertainties; e.g., supply disruptions or customer migration to competitive suppliers.
  - There should be ongoing senior management and Board of Director's review of supply procurement effectiveness.
  - An ongoing review of portfolio components and targets, conformity of purchases to the portfolio, compliance with price and volatility mitigation targets, compliance with risk management programs, and performance benchmarking against energy markets and other utilities.
  - The interests of customers should be the predominant drivers of policies and procedures for operation of the company's supply portfolios at the distribution level.
- Procurement and Transactions
  - Procurement decisions should be consistent with portfolio design, should balance short- and long-term considerations appropriately, and should generally apply competitive approaches.
  - NYSEG and RG&E should take steps to assure a robust response by suppliers to assure competitive results representative of market conditions.
  - Procurement and scheduling responsibilities should be exercised by personnel with levels of experience commensurate with the size of the energy portfolio.
  - Procurement decisions should be clearly documented, subject to levels of approval commensurate with their costs and risks, and made according to comprehensive, appropriate procedures.
  - Supply procurement performance should be continually monitored, evaluated and be part of employee performance reviews.
  - Non-competitive purchases should require and routinely exhibit sound and complete documentation of their justification.
  - Financial and procedural audits should be conducted routinely to check for errors and assess compliance with procedures.
- Risk Management
  - A comprehensive risk management program should be in place that is approved and overseen by the board and, in turn, an appropriate senior management committee.
  - The risk management program should contain all of the elements required to mitigate appropriately the risks that energy-related financial transactions impose.
  - Counterparty pre-qualification and credit limits should operate under structured and rigorously applied criteria, with exceptions and violations regularly and faithfully reported and subjected to affirmative response.

- Hedging transactions should take place under a comprehensive program that applies volatility standards, identifies allowable transaction types for meeting those standards, establishes targets for total and by-transaction type, appropriately limits authorized traders, requires regular reporting of results, and faithfully reports and provides for an effective response to exceptions and violations.
- Each company should document energy procurement, trading and risk management protocols with well defined risk controls, risk tolerance measures and structured portfolio targets.
- Each company should be able to identify an officer of the company who serves as the chief risk officer who can independently monitor and approve financial and physical energy transactions.
- The companies' energy procurement and trading desk should be managed by a team of highly competent procurement specialists who abide by a strict code of conduct and comply with all business and regulatory standards.

B. Findings

1. Electric Portfolio Design

Management of the NYSEG and RG&E electric supply portfolios falls under two Managers of Electric Supply and their subordinates, performing under the direction of the Vice President, Energy Supply. DSO portfolio management includes the planning, procurement, and management of electric resources for those full-service customers who have not switched to a competitive electric supplier. The first part of this process, as described in this section, comprises the formulation of a portfolio design or long-term plan that provides a roadmap for the acquisition of electric resources over the long term. Following sections of this chapter address the contracting, hedging, scheduling and other operational aspects of electric supply procurement.

NYSEG and RG&E have stated their strategy in the area of electric supply procurement as follows:

> *The companies' strategy, supporting retail access and generation divestiture, is based on the Commission's Policy to Promote Competition. The companies believe that its approach, procurement in the NYISO market and financial hedging, is the best way to accomplish the Commission's policy.*

Neither company has set specific, long-term goals for volatility or for pricing for DSO customers. The companies do set annual "targets" of two percent below the market, as measured by coefficient of variation ("CoV"), for volatility. According to company management, the budget estimate for DSO electric resource pricing serves as an annual "goal" for pricing.

IUSA states that no other written policy, procedure, or objectives related to portfolio design exist for electric procurement. IUSA represents that little electric supply optionality had existed in the past, due to the magnitude of restructuring buy-back and NUG contracts in place until the 2007-2011 period. Several larger NYSEG NUG contracts (most priced well above market) have expired during this period, and inexpensive NYPA hydro contracts (priced at only about

$5/MWh) of 455 MW were re-allocated away from customers of NYSEG and RG&E in 2011. IUSA also intends to allow Nine Mile 2 purchased power contracts of 183 MW with NYSEG and 144 MW with RG&E to retire without renewal on November 30, 2011. The companies' energy supply portfolio focus has been on replacing these contracts with market purchases of energy from NYISO, and financial hedges to moderate the volatility of energy purchases. Capacity contract purchases come from a variety of market sources.

2. NYSEG and RG&E Hedging Plans

Liberty sought to determine what analysis and structure underlies the determination of an optimum electric supply portfolio for planning and operational purposes. Company representatives stated that they have not had an electric-supply plan that extends past two years. However, the companies did provide a hedging presentation made to NYPSC representatives on March 24, 2010. It included summary analysis and a recommended hedging plan, which has been implemented in 2010 and 2011.

In 2007, the NYPSC Order in a generic hedging proceeding (Case 06-M-1017) for New York's six major electric utilities sought to address implementation of hedging programs through collaborative discussions with Staff. The NYPSC also ordered the companies to submit quarterly reports to Staff, and established a Coefficient of Variation ("CoV") as the metric for measuring the volatility of the utility supply portfolios. The Commission did not, however, establish specific CoV target levels.

The hedging case Order stated:

> *Once the measurement standards and volatility goals are in place, utilities shall meet with the staff annually on the portfolio management strategies it will implement, and the commodity supply instruments and hedging arrangements it will deploy, to achieve its goals.…*
>
> *Therefore, the guidelines adopted here shall consist of a directive that each electric utility develop standards and goals for measuring and constraining volatility in a collaborative or other administrative process, subject to annual Staff review of the strategies for achieving the goals.*

NYSEG proposed to Staff in 2007 that it maintain the level of hedges in place at that time through purchased power contracts; these hedges covered about 60 percent of load. RG&E sought to maintain its higher levels of physical hedges attained through purchased power contracts. IUSA has reported that, in 2008 and 2009, the Staff encouraged higher levels of hedging for NYSEG and extension of the hedge period to more than one year. Staff also reportedly suggested in 2009 that NYSEG perform a "probabilistic analysis to determine the best hedge procedure to minimize the CoV and costs."

NYSEG completed a probabilistic analysis (covering 2011 through 2013) of various hedging strategies using the *@Risk* model, and presented the results to Staff on March 24, 2010. The analysis modeled hedge levels of 60 percent, 75 percent, and 90 percent over 1, 2 and 3 year periods. The analysis assumed no renewal of the NYSEG Nine Mile 2 purchased power agreement after its end in November 2011; financial hedges replaced this physical hedge. The analysis assumed continuation of the NYPA rural and domestic hydro-power allocations. These allocations were discontinued in 2011. The analysis showed that 90 percent hedge levels applied evenly over three years produced the lowest CoV, but IUSA noted that results at this level were not significantly better than those produced at the 75 percent level. IUSA also noted that 3-year financial hedges might not prove attractive, given lack of market liquidity for this long a duration. IUSA did not differentiate the cost in dollars per megawatt hour of the nine portfolio permutations among the options in the analysis. The presentation noted only the "Increased opportunity for lower overall portfolio prices" with increased hedging. NYSEG recommended hedging at a [redacted] percent level on a [redacted] basis over a [redacted]-year period for the DSO customers. RG&E's legacy purchased-power resources exceeded [redacted] percent at that time. IUSA recommended the same hedging program for RG&E when the legacy hedges fell below the [redacted] percent level.

NYSEG has implemented a hedging plan that includes purchasing energy hedges on a [redacted]-month rolling basis at the steady rate of [redacted] of the open position per [redacted]. The plan called for NYSEG to purchase [redacted] MW of on-peak and [redacted] MW of off-peak energy hedges during the last three quarters of 2010 and the four quarters of 2011 to reach the [redacted] percent target. RG&E is expected to require small additional energy hedge positions of [redacted] MW for only a few months through 2013.

Plans for assuring the capacity required by the NYISO for deliveries involved additional purchases executed in [redacted] amounts for the following [redacted] years, until IUSA met the full unforced capacity ("UCAP") capacity requirement of around 2,250 MW for both companies. NYSEG would acquire [redacted] MW of capacity hedges over the same [redacted] quarters in 2010 and 2011, if the NYPA hydro allocations continued, and about [redacted] MW more if terminated. RG&E would require [redacted] MW of additional capacity to reach the total UCAP target by 2012.

IUSA met with NYPSC Staff on March 31, 2011 to provide an update on the hedging program. The companies report that they shared historical hedge performance data, and discussed future hedge plans. Staff asked whether the companies thought it might be worthwhile to review their hedging programs, given recent decreases in market prices and assumed decrease in market volatility. The companies agreed to review market conditions and their hedging programs. That review subsequently produced the same conclusions provided in the March 24, 2010 presentation. The companies therefore did not change their hedging programs.

3. Procurement and Transactions

The electric procurement operations and trading desks for both NYSEG and RG&E are located at the Kirkwood facilities in Binghamton, New York. The trading desk is a 24-hour a day operation; each operations day begins at approximately 7 AM. The staff on the trading desk includes five real-time traders and three day-ahead traders. The senior day-ahead trader maintains remote capability such that he may take over the transactions from a remote location using his laptop.

Liberty interviewed the managers of both the gas and electric energy traders and was provided a guided tour of the facilities. We also observed actual transactions and followed the input of transactions into the Allegro tracking and information system and observed the actual information flow through to the mid- and back-office for verification and confirmation, and ultimately for payment or receipt.

Electric procurement operations begin with forecasts of load and resources that are used to plan day-ahead trading that flows into real-time operations. The primary tool used by the trading desk to develop bids for the day-ahead and real-time markets is an EPRI model called ANNSTLF. The EPRI model is used to calculate the next day’s hourly loads based on a neural-network algorithm that factors both the typical load shape for that day and the projected weather conditions. The EPRI website notes that “ANNSTLF develops a load model through a process involving past historical load and weather data. The non-linear processing capability of neural networks enables ANNSTLF to capture the complex load-weather relationship that is difficult to model for conventional forecasting techniques. The impact of several weather variables such as temperature, relative humidity and wind speed can be taken into account by ANNSTLF.”

The companies have also developed a complementary model that produces "like days,” which generate load shapes within a one-to-two degree change in weather for the past one thousand days. The like-day model is used to compare and validate the forecasted loads and to make manual adjustments.

Liberty also interviewed the senior day-ahead trader to review daily activities and day-ahead load forecasting methods. In addition, the trading floor was observed and load models reviewed that are used each day, as well as the steps that are completed to bid in the day-ahead and real-time NYISO markets. The EPRI model was demonstrated, including examples of the use of the like-day model to make manual adjustments. The adjustment process calls for not only analytical assessment, but also sound judgmental analysis based on experience.

The EPRI model forecasting error band ranges between one and two percent in the day-ahead market, which compares to an industry average of about 3.5 percent, according to the company. Real-time savings generated by the traders is tracked; around $700,000 in electric supply savings were estimated by the company for January through September 2011 due to adjustments to the day-ahead bids. While the trading desk does not have a deep and detailed procedures manual, the companies have developed a detailed day-ahead scheduling checklist that walks through every process that needs to be accomplished throughout the day. The checklist is completed daily by either a real-time or day-ahead trader.

4. Risk Management

Risk management for NYSEG and RG&E is focused on two separate areas of risk exposure. The first is risk management for commodities and financial instruments that is overseen by the Risk Management Oversight Committee and is a focus of this chapter of the report. The second area is overall business and operational risks that face the companies, otherwise known as “enterprise risks.”

a. Commodity Risk Management

Risk management for NYSEG and RG&E is performed primarily by the IUSA Director, Risk and Insurance, and supported by a Manager, Energy Supply Risk. During Liberty's management audit, the director was promoted to new responsibilities, and the manager was promoted to the director position to take over the risk and insurance responsibilities.

The Risk Management Oversight Committee ("RMOC") is the risk committee for NYSEG and RG&E. The RMOC holds monthly meetings in which commodity risks are the exclusive focus. Commodity risk issues may include pipeline risks, customer defaults, counterparty risks, commodity exposure and collateral. The RMOC minutes are provided to executives, but do not go to a higher committee in the organization. RMOC members are the VP-Energy Supply and directors and managers within the electric and gas procurement, risk management, and auditing groups at IUSA. The RMOC provides risk management oversight for the three utility OpCos.

The Risk Manager reports that Iberdrola SA (Spain) risk management performs counterparty credit analysis for supply procurement for the New York companies and sends reports to the New York operations. The Energy Supply Risk Manager and analyst use this and other credit information, and provide updates on credit risk and counterparties in reports to the RMOC. Reports are also prepared by the director and manager for Iberdrola SA risk management, which are operational and financial (versus commodity-related) in nature. The companies' main energy supply counterparties are NYISO and NEPOOL; there are less than 10 other regular counterparties for financial energy transactions. Most transactions are with the NYISO and are relatively short-term.

The primary operating and risk management procedural document for energy supply is the Energy Supply Risk Management Procedures Manual, dated May 31, 2011. The manual details processes for transactions, risk reviews, supply bidding, and billing confirmations.

Iberdrola SA has a risk committee at the top holding company level. A monthly risk meeting is held with the SA CFO and risk managers from around the world. The IUSA risk director participates by video conference monthly, and travels to Spain for meetings twice per year. On a monthly basis, the director provides a retail credit risk report (bad debt) and the wholesale market exposure report to Iberdrola SA. The director also provides quarterly key risk reports and presentations to the SA risk committee that are high-level reporting documents for the current risk processes.

According to company management, the RMOC is a working risk committee, and is not an executive-level committee. Risk management structures at utilities routinely include both a working risk committee and an executive risk committee; the executive committees are established to ensure that executive oversight and knowledge of important risk management operations are developed at the local level. During Liberty's field work in this area from April through July 2011, Company managers acknowledged that *there was not an executive risk management committee in either the utilities or at IUSA*. The IUSA holding company had a risk policy with limits and indicators on commodities and financial instruments, but does not have an executive risk committee. According to the company, an executive risk oversight committee at IUSA was established in November 2011.

The billing and transaction risk management operations related to electric procurement are located at the Kirkwood facility and report to the VP-Energy Supply. This department's functions include electric and gas invoicing, deal confirmation management, credit and collateral management, internal IT support and SOX compliance. Oversight of these functions is the responsibility of the billing andrisk manager, who provides an independent review of transactions, oversight of counterparty credit worthiness, compliance checking for the code of conduct and the review of software tools (Allegro) used to manage and monitor transactions flows from the front through the back office. Credit and collateral reports and exception reports are prepared both weekly and monthly for the RMOC.

b. Enterprise Risk Management

The companies have a risk management identification and analysis function that is headed by the director. This function is primarily a top-down identification of critical risks which include rate case penalties, reliability performance, merger commitments, major projects such as the CMP transmission line, and the New York management audit.

According to company management, risk management started in about 2002 at the US companies, and is still developing. For instance, the Company did not use management surveys to initially identify key risks. The director identified risks, and tested them with managers of functions and with some executives. The director eventually prepared quarterly presentations on risk to the Energy East Board of Directors audit committee, specifically identifying risk areas that he believed needed focus.

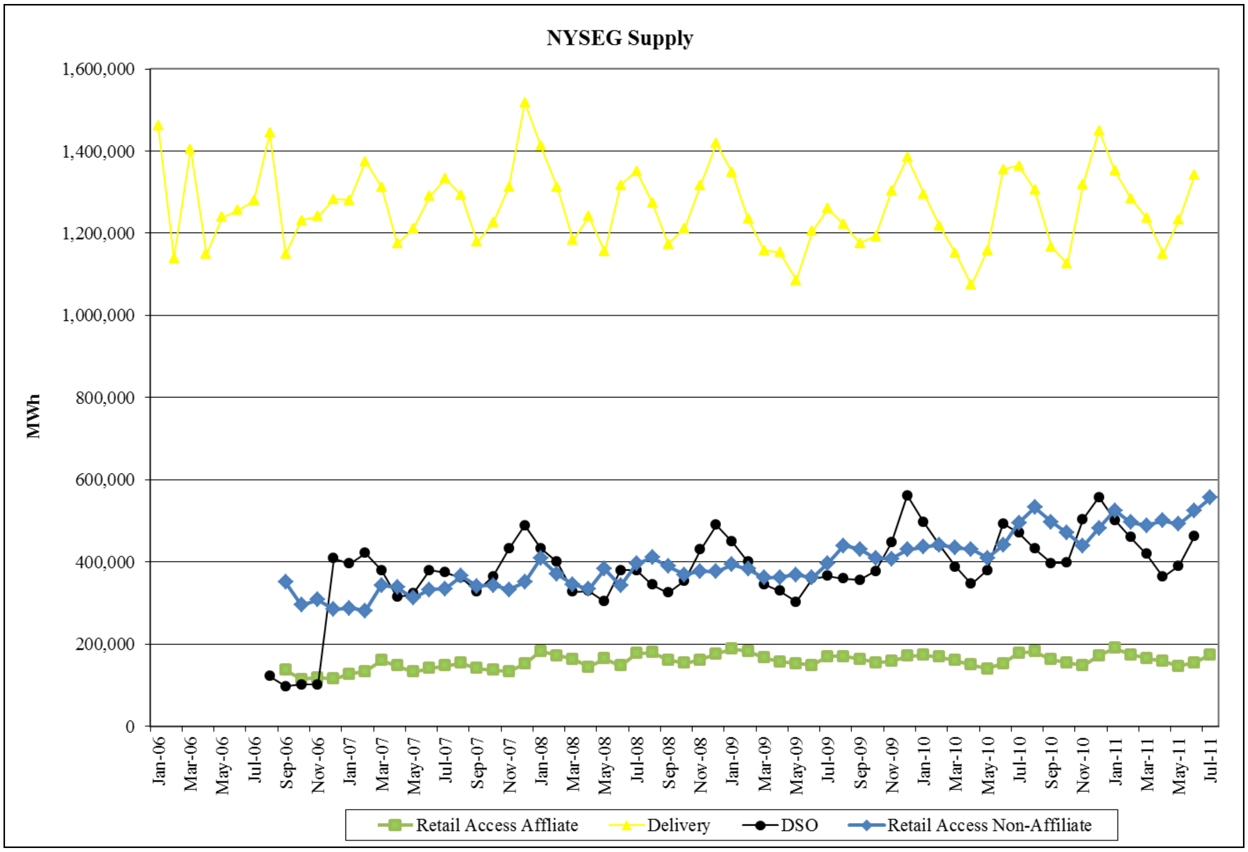
The Iberdrola risk managers reviewed some of the US risk management reports following the merger and believed that the reporting system needed to be formalized. The Key Risk Reporting system was established in response, and monthly reports are sent to 23 directors and executives that identify the top 10 to 15 risks for the US companies. The risks identified include key and unique risks, and not business-as-usual risks. For instance, currently reliability indicators such as CAIDI and SAIFI are risks to maintain, as well as snow and storm damage. Risk management also performs risk analyses on an ad-hoc basis, with input on risks from managers.

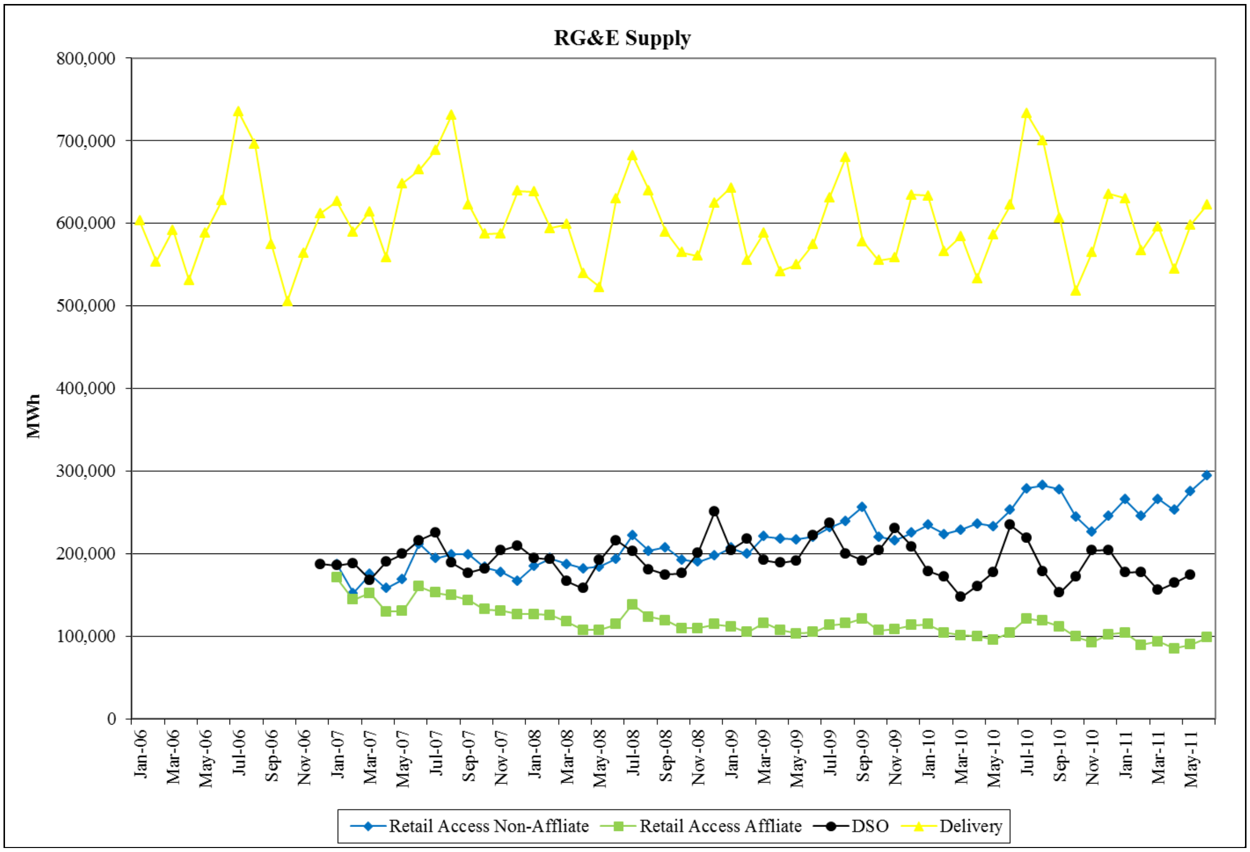
Another function of risk management relates to performing probabilistic analysis of performance against budgets. A Monte Carlo simulation is layered onto budgets to do probabilistic views of the budget performance. The companies are also building a Monte Carlo simulation around a five-year strategic plan that is being developed. This is a key focus of risk management that is apparently driven by the holding company at Iberdrola SA, and is not a common responsibility for utility risk management groups.

5. Historical Total Delivery Electric Load and Suppliers

The NYSEG and RG&E total deliveries to end users have remained flat during the last 5½ years, as the top lines in the charts below show. The charts also divide the total deliveries by three categories: retail access by non-affiliates, retail access by the Iberdrola affiliate, and the remaining DSO load. The 2011 DSO load has comprised about 35 percent of total deliveries for

NYSEG and 29 percent for RG&E. The DSO loads have increased for NYSEG, but decreased for RG&E since January 2006.





6. Historical DSO Load and Resources

NYSEG and RG&E have obtained electric energy and capacity during the past several years from five primary sources:

- Purchased power contracts, which include repurchase contracts from the Nine Mile 2 and Ginna nuclear power plants as part of the regulatory agreements to sell the plants during the restructuring process in New York
- Bilateral capacity purchases
- Several substantial legacy non-utility generation (NUG) contracts, all of which had expired by June 2009
- Power purchased from the New York Power Authority (NYPA) under six contracts for NYSEG and four for RG&E
- Purchases made from the NYISO energy, capacity, and ancillary services markets.

NYSEG and RG&E have retained a small amount of their own generation resources, all of which get bid into the NYISO and are regularly scheduled. RG&E has 20-40 MW of hydro and 60 MW of combustion turbines in rate base. NYSEG has 40 MW of hydro in rate base. NYSEG also leases 7 MW of combustion turbines.

NYSERDA centrally purchases wind power for participating New York utilities. NYSERDA sends out RFPs for 10-year or more contracts, and contracts with wind generators. Participating utilities pay NYSERDA a rate that funds the program. The providers get paid when they bid, providing up-front support for funding. Hydro Quebec may sell into NYSERDA. NYPA and LIPA are exempt, and are not members.

Electric restructuring required the companies to sell their electric generating plants, except for the previously mentioned hydro power and combustion turbines. The companies retained their NUG contracts. These contracts have proven relatively expensive when compared to market and the companies' other legacy resources.

The following table summarizes the major NYSEG and RG&E purchased power contracts from January 2006 through July 2011.

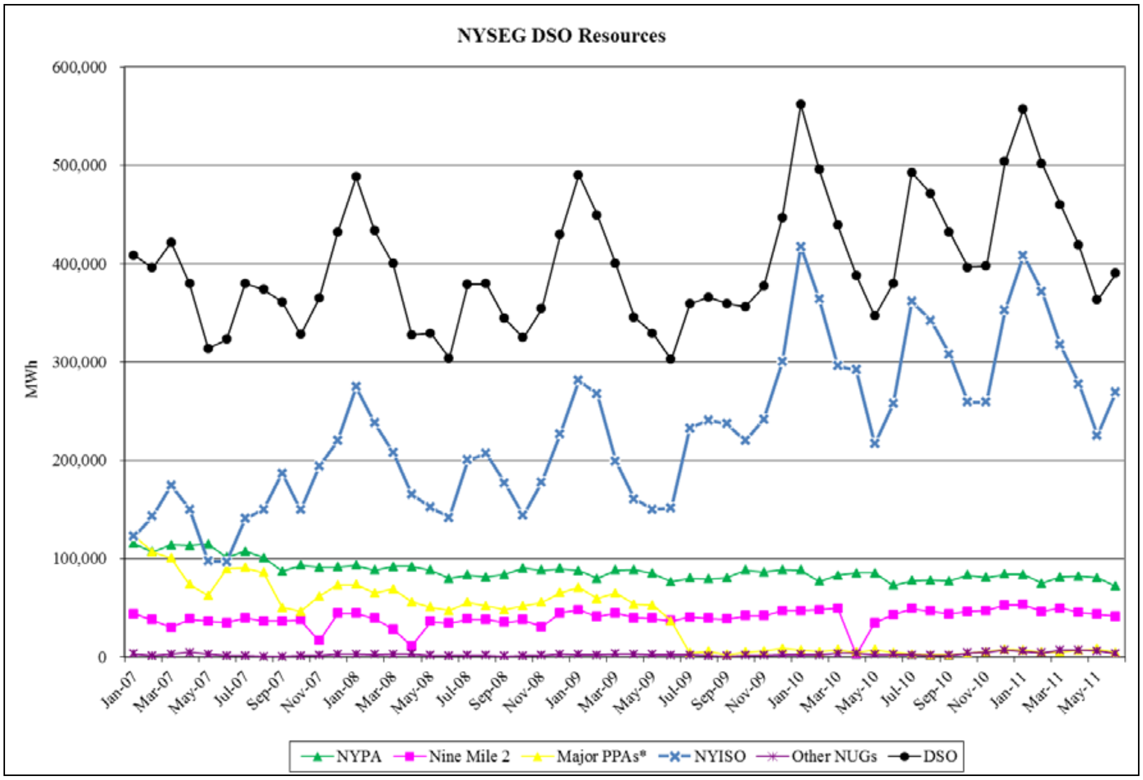
NYSEG/RG&E Major Electric PPAs 2006-2011

Contract	Nominal Volumes (MW)	Contract Type	Contract Expiration	Last Contract Year Pricing ($MWh)
NYSEG				
Nine Mile 2 – nuclear	183	Restructuring Buy-back	November 2011	$22-$75
NYPA hydro (3)	317	NY residential hydro allocation	July 2011	$5
NYPA Other (3)	125 decreasing to 51	Economic Development, Expansion Power, Power for Jobs	41 MW are continuing	$7-$35
Falcon Seaboard/Saranac	240	NUG	June 2009	$90-$123
Lockport Energy	200	NUG	October 2007	$110-$115
Indeck	55	NUG	April 2006	$60
CL2	55	NUG	August 2007	$57
CL10	25	NUG	April 2008	$122
Allegheny hydro 8 & 9	42	NUG	Continuing	Market Price
RG&E				
Ginna – nuclear	500	Restructuring Buy-back	July, 2014	[redacted]
Nine Mile 2 - nuclear	145	Restructuring Buy-back	November 2011	$22-$75
NYPA hydro (3)	138	NY residential hydro allocation	July 2011	$5
NYPA Other	6 decreasing to 1	Power for Jobs	Continuing	$35

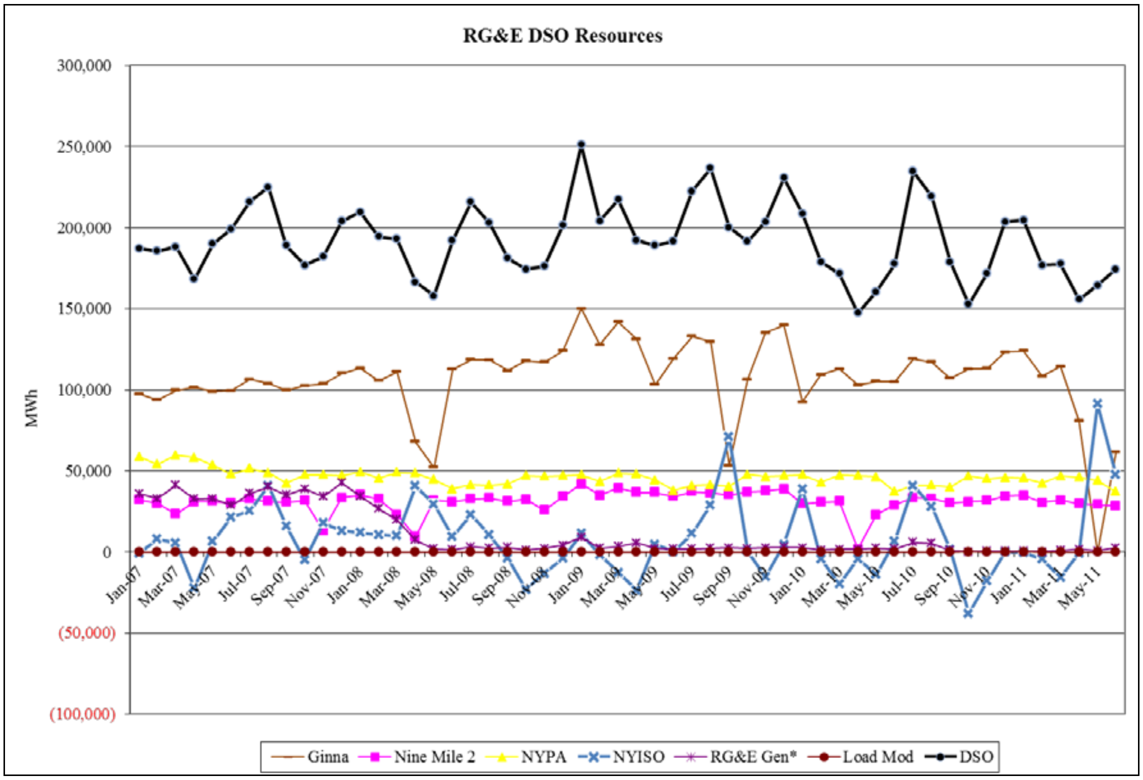
Both companies also have a number of small "load modifier" contracts, consisting primarily of hydro contracts priced at either the market price or a flat rate for all hours.

The NYPA contracts have provided a substantial amount of inexpensive capacity and energy for NYSEG and for RG&E. The total cost of the Nine Mile 2 contracts have remained below market for both companies during the past five years. The total cost of the Ginna contract has been near market prices for the same period.

NYSEG purchased most of the energy required for the DSO load from the NYISO during the past five years, as shown in the charts below.



RG&E has purchased the greatest volumes of energy for DSO customers from the Ginna contract, NYPA and Nine Mile 2. NYISO energy purchases have produced the remainder of required energy, especially during nuclear plant outages.



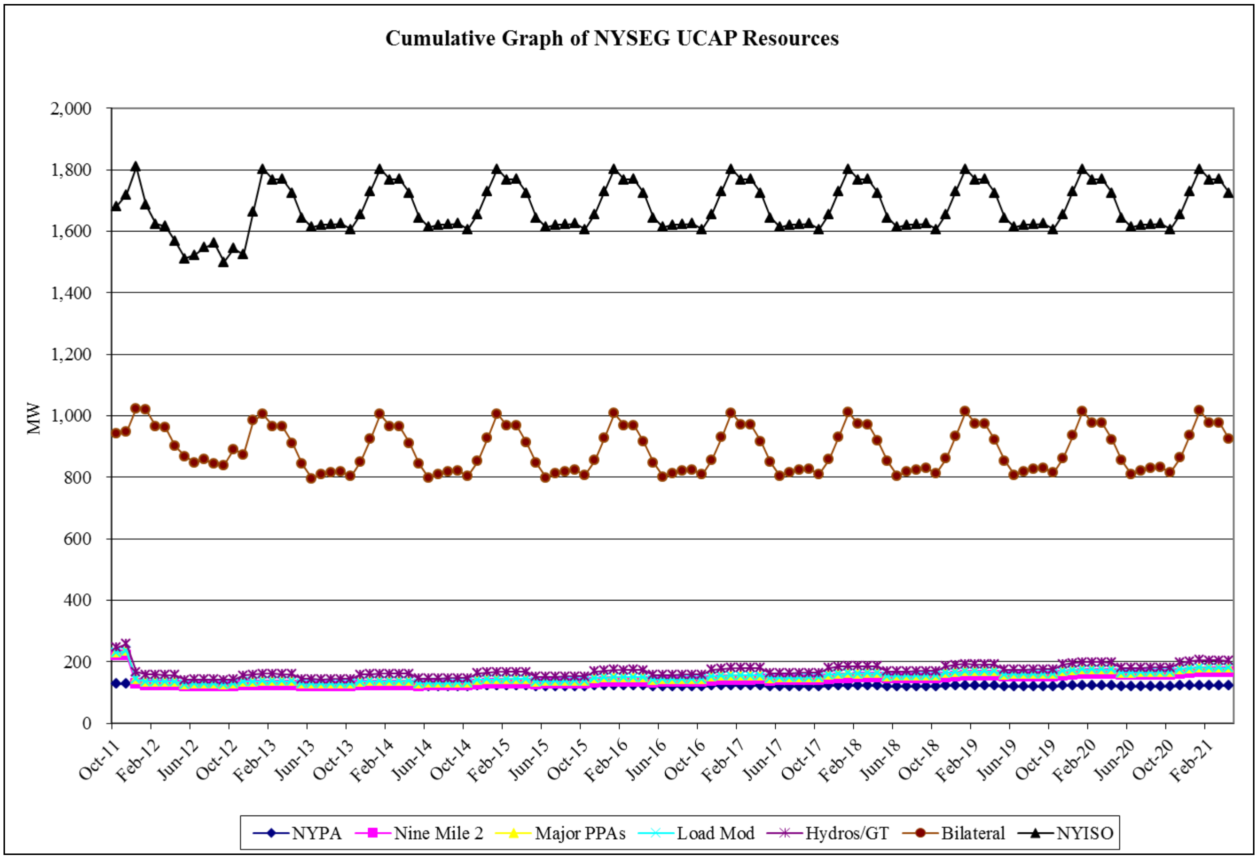
7. Historic Capacity Requirements and Resources

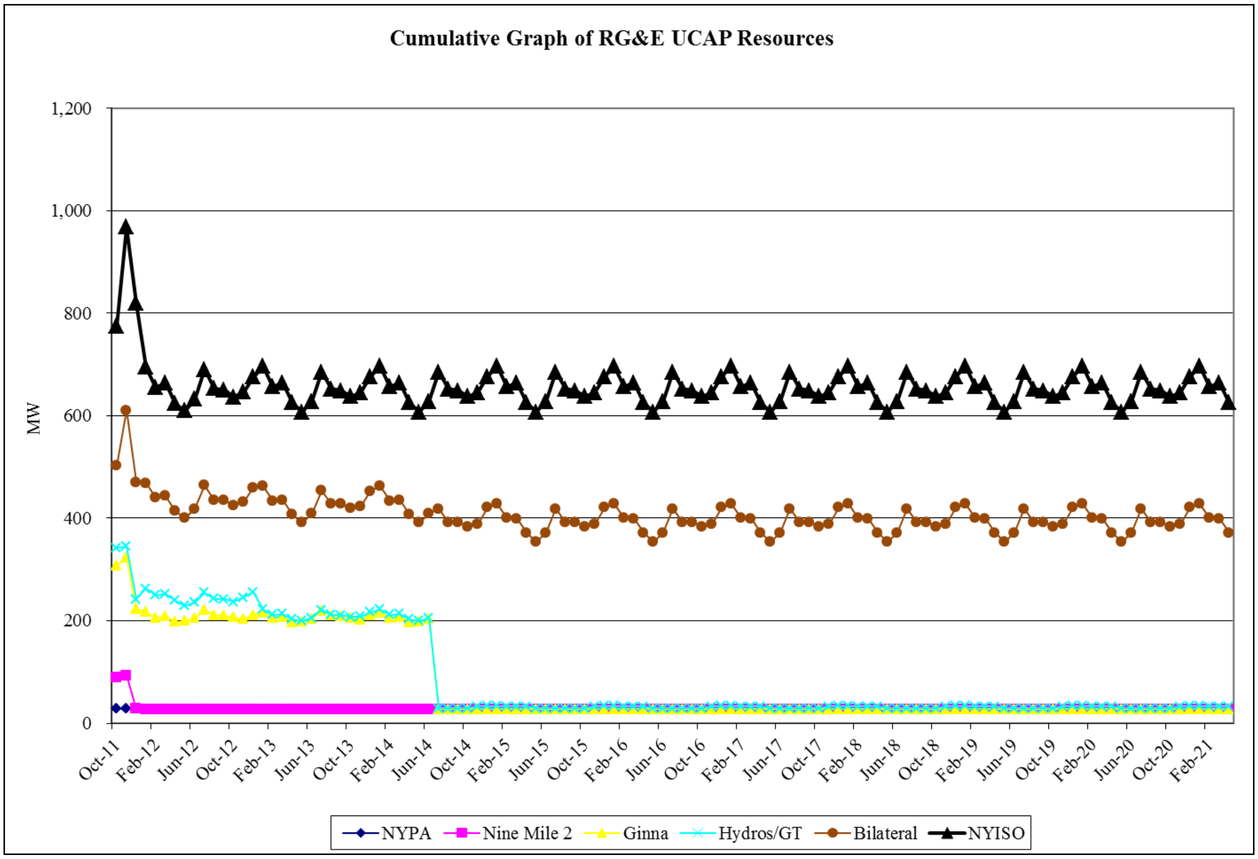
The NYISO establishes UCAP capacity requirements for New York's load-serving entities. The UCAP capacity requirement established for each utility covers deliveries made by the distribution utilities, as well as a reserve requirement for reliability purposes. The UCAP requirement has been about 2,250 MW for NYSEG and RG&E combined. The companies must buy contracted capacity from bi-lateral sources or from NYISO to supplement the capacity in their purchase contracts. The NYISO's installed capacity ("ICAP") auctions include three types: strip, monthly, and spot.

Capacity purchases are made quarterly, with one-eighth purchased each quarter starting two years ahead of the requirement date. NYSEG and RG&E bought capacity for 2012 and 2013 during the summer of 2011. The market for 50 MW contracts has proven to be the most liquid. Contracts for 25 MW prove less so, but allow more purchasing flexibility.

Biannual NYISO capacity auctions offer six-month "capacity strip" contracts. The strip auctions occur in April for the summer (May-October) contracts and in September for the winter (November-April) contracts. The companies may bid in this auction for capacity requirements for the entire six-month period. A second NYISO opportunity comes with the monthly auctions, which allow bids for the upcoming forward month and any other months remaining in the same six-month capability period. Spot auctions provide the third and final opportunity to buy capacity prior to delivery. NYISO acts on behalf of the load serving entities in these auctions, assigning capacity to cover any shortfalls at the spot auction clearing prices.

Informal bi-lateral markets for capacity purchases also exist, allowing arrangements through brokers and through direct purchases from generators. NYSEG and RG&E buy a majority of their capacity from these sources. The charts below show the sources of capacity purchases from 2006 through July 2011.





8. DSO Load Forecasts

The rate department prepares two-year load forecasts for use as the foundation for electric supply planning. The Total Corporate Supply load forecast is consistently used across the companies. The DSO forecast (forming a portion of the Total Corporate Supply Forecast) results from the following process:

- Customer class unit estimates are prepared using econometric models. These forecasts then get allocated across service classes using the most recent 12-month distributions.
- The class unit forecasts are then distributed between the rate options using the most recent trends (which reflect the most recent customer migration activity).
- The individual service class-rate option forecasts are summed together to create a total monthly billed delivery forecast.
- The monthly billed delivery forecast is then converted to a calendar month forecast.
- Summing the DSO calendar month units' forecasts together and then adding back in distribution system losses yields the calendar month DSO supply forecast.

Demand-side management and energy efficiency impacts are "implicitly assumed to be embedded in the actual historical data," by customer class, which is used in the econometric models to generate the forecasts. Currently, the companies are developing a forecast of 2012 energy efficiency impacts. Once this forecast is readily available, a manual adjustment to the 2012 forecasts will be made to reflect these new, incremental impacts.

Liberty inquired about the impact of additional customer migration, DSM and energy efficiency in the long term on energy supply. The response was that such considerations are long-term; forecasts for energy supply only address two-years. IUSA, however, prepared "rough" DSO load forecasts for the next 10 years, in order to show DSO supply resources, as presented in the next section. Both utilities forecast a slight increase in DSO load for the next 10 years. Each utility estimates an approximately one percent in annual growth in total load (and in DSO load) over the long term.

9. Procurement for Future Requirements

The strategy regarding electric procurement for future DSO requirements is simple: new requirements or the expiration of legacy PPAs will be met with financial hedges on [redacted] percent of the load. All incremental energy requirements will be purchased from NYISO at the applicable market price. The next chart shows this approach clearly. Total DSO energy required is the top line; NYISO energy purchases match this amount, after the NYPA contracts and Nine Mile 2 fall off in 2011. Financial hedges of [redacted] percent of the DSO load are also clear.

[redacted]

For RG&E, the Ginna contract will expire in 2014. At this time, the contract will be replaced by NYISO energy purchases and financial hedges on [redacted] percent of the purchases.

[redacted]

Supply-portfolio costs have been well below market pricing during each year to date. This result has come due to legacy NYPA hydro contract pricing (less than $5 per MWh), and the Nine Mile 2 PPA pricing being at below market rates. The physical hedges provided by these contracts have also reduced DSO price volatility. NYPA has withdrawn its sizeable hydro allocations to the companies in accordance with the Recharge New York legislation, making payments of about $60 million per year to compensate for the loss of this resource. The companies do not plan to renew their capacity contracts with Nine Mile 2 when they expire on November 30, 2011, nor do they plan to explore other PPA alternatives in the market to replace these resources. They will be replaced by financial hedges and NYISO purchases for energy, and by bi-lateral physical hedges for capacity.

C. Conclusions

1. **The companies do not have a comprehensive, long-term approach with clear goals and objectives for an electricity-supply "portfolio design."** *(Recommendation #1)*

Liberty asked several times, in data requests and in interviews, for the companies' portfolio design and optimized plan for the electric resources required to serve its full-service DSO customers and system capacity requirements over the long term. The companies have the 2010 hedging plan, but they do not have a comprehensive plan that includes specific long-term goals for both volatility and pricing levels, and that optimizes the portfolio structure in pursuit of these goals. There does exist an annual goal for portfolio volatility of two percent below market volatility, as measured by CoV.

The companies have also not included market alternatives such as purchased power agreements for energy and capacity or physical energy hedges in analyses of an optimized resource portfolio that would most effectively meet DSO and capacity requirements. With regard to DSO energy purchases, the companies plan to make all incremental purchases of energy from the NYISO and to buy only financial hedges as part of their hedging plan.

A long-term portfolio design and plan should determine the general types of supply resources and their duration, as well as the mix of such resources that will be most effective given forecasted energy markets. Setting specific long-term objectives lays the cornerstone for portfolio design and effective management of energy procurement. Without first specifying objectives to offer guidance and limits, a company is unlikely to design and manage a portfolio effectively. By not considering all market alternatives in their hedging analysis, the companies have not yet determined their optimal portfolio for minimizing volatility and energy cost levels. The companies already have used a tool, the *@Risk* model, which can perform such an optimization analysis using a probabilistic, Monte Carlo simulation approach.

2. **The companies have specifically excluded new bi-lateral purchased power contracts, physical hedges and market alternatives that have durations of more than two years as potential components of their electric supply portfolio.** *(Recommendation #1)*

The companies have not explored purchased power contracts as part of forward-looking supply portfolios. They, therefore, are not aware of PPA pricing and terms that may be available in the marketplace, outside of the NYISO. The company does monitor New York and PJM pricing for financial hedges. The companies have provided a variety of reasons for not considering purchased power, physical hedges or longer terms. Liberty does not find any of them persuasive in justifying the lack of consideration of alternatives that could lower DSO supply costs.

Some of the reasons offered for not exploring PPA alternatives are:

- There is an "old legacy bias" (especially in upper management) against PPAs, because the New York 6-cent rule for NUG contracts was in place for 20 years and left a bad taste in people's mouths.
- "The companies believe that a long-term, unit-contingent, fixed price bilateral PPA is analogous to generator ownership without any potential for upside ratepayer benefit."
- "Long-term bilateral contracts with generators have two significant risks: (1) operating risk – the supply is unit contingent and (2) price risk – the fixed price could end up above market."
- Physical contracts create delivery risk, and involve more credit risk than does buying from the NYISO.

We do not find the above reasons to justify a failure to explore the market for beneficial resources. First, the legacy bias against PPAs due to issues with NUG contracts is irrelevant; freely-entered market PPAs are not must-take NUG contracts; they must stand or fall on market competitiveness. Second, the companies describe all PPAs as "long-term, unit contingent, fixed price bi-lateral." However, PPAs may be short or medium-term, may not be unit contingent, may require replacement power in the event of outages, and may be fixed price or be cost-related. In addition, the credit and collateral requirements of NYISO purchases are now greater than that of PPAs.

Market alternatives such as medium or longer-term PPAs and physical hedges should be considered when forming the DSO supply portfolio. Of course, the companies should only enter into electric supply arrangements that are superior to other alternatives, and that fit in an optimum supply portfolio.

3. **RFP solicitations have not been considered for soliciting and acquiring energy, hedging and capacity resources.** *(Recommendations #2 and #3)*

The Companies currently buy incremental amounts of energy exclusively from the NYISO to meet the needs of DSO customers. The hedging plan for this energy includes the [redacted] purchase of exclusively financial hedges for energy to be purchased [redacted] years in the future. Physical hedges are not considered; the companies use only financial hedges.

Capacity purchases for UCAP requirements are purchased through brokers and generators using bi-lateral contracts. Liberty believes that the companies may be not considering some attractive market resource options that may be available by not utilizing RFP market solicitations.

The use of RFP market solicitations has the potential to uncover electric supply opportunities that are not currently being considered, are less well known, have had changes in source status or availability, or may have specific reasons such as unsold energy and capacity to sell at below-market prices. RFP solicitations have successfully uncovered attractive resource alternatives when utilized in many other states, as well as in New York.

4. **The reluctance to enter into electric supply PPAs and hedges of more than [redacted] years is based on rate recovery fears.** *(Recommendation #1)*

The companies have a policy to not enter into PPAs and physical or financial hedges with terms of greater than [redacted] years. The primary reasoning provided for such a stance is avoidance of rate-recovery risk, because longer-term contracts could be deemed to be imprudent by the NYPSC. If a longer-term contract later becomes more expensive than changing market prices, the companies are at risk of such recovery disallowances. A second justification is that the companies fear that they may lose substantial DSO load through customer migration, which could produce "stranded contracts" that provide unnecessary electric supply.

Each of these arguments has some merit on the surface. The companies should not be expected to face substantial recovery risks on its electric supply, if prudently incurred and communicated with the NYPSC Staff. Liberty does not consider the second recovery risk (stranded contracts) to be significant, and should be mitigated by the company providing refined long-term load forecasts for planning purposes.

Various NYPSC policy statements and Orders regarding electric supply portfolios since 2004 have consistently included statements against placing limitations on the length of longer-term purchases or hedges used to serve mass market customers.

In the "hedging proceeding" Order in Case 06-M-1017 dated April 19, 2007, the Commission stated the following:

> *No particular limitation on the length of a hedging arrangement will be imposed on electric utilities as a requirement for the structuring of the portfolios supporting hedged service to mass market customers. Artificially restricting the length of the term of an electric hedging arrangement could be a disadvantageous constraint that would reduce the flexibility utilities need to act in the best interest of their mass market customers. It is expected, however, that utilities will properly develop and prudently manage their resource portfolios, and nothing here relieves utilities of that responsibility.*
>
> *Instead of adopting a proscriptive limitation on the length of electric hedging arrangements, electric utilities are advised that they may enter into hedges of the appropriate length for the purpose of constraining volatility. For example, a utility might find an opportunity to make longer-term purchases at an attractive price from a generator whose variable costs of production are predictable and comparatively low, like an owner of a hydro or nuclear facility. Electric utilities, however, would also be expected to avoid hedges that are unduly expensive or risky because of their length or other unfavorable characteristics. This expectation will constrain hedging activities to instruments and arrangements of the proper length without adopting a specific limitation on the length of time deemed acceptable.*
>
> *A long-term contract entered into for the purpose of encouraging the development of new resources, however, would be outside the scope of this hedging policy. As a result, the approach discussed above will enable electric utilities to avail themselves of longer-term hedges if opportunities arise for them to constrain volatility over a longer period of time, but will not promote activities, or raise cost recovery issues, that should be decided in the Phase II proceeding discussed below.*

Liberty believes that the stated Commission policy encompasses longer-term PPAs and hedges as part of DSO portfolios where beneficial in reducing volatility and pricing levels. However, the NYPSC Staff has advised Liberty that the Commission's policy of long duration has been to address the costs of long-term electric-power purchases in rate cases, rather than to approve their prudence when executed. This statement has tempered Liberty's Recommendation #1 to acknowledge the risk to the company of entering into longer-term instruments.

With regard to customer migration risk, the "rough" 10-year DSO load forecasts show a slight increase in load for both companies over the long term. Customer migration leveled off long ago, and DSO loads did not decrease substantially from 2006-2011. In addition, any longer-term PPAs or hedges included in the supply portfolio would be for only a portion of the DSO load. These factors make the risk that load will fall below contracted resources exceedingly small. The potential benefits of using attractive alternative instruments greatly outweigh this slight risk.

5. **The companies' planning for electric supply procurement is not sufficiently long-term to capture the load requirements and resources past two years.** *(Recommendation #1)*

Refined load forecasts for the companies do not extend beyond a [redacted]-year horizon, as noted in Chapter IV as well as in Conclusion #1 above. Electric resource plans, as represented by the current hedging plan, run only through [redacted], which Liberty considers too limited a time horizon to optimize planning for the future. The companies' planners prepare required peak load requirements forecasts for 10 years; however, refined load and electric resource plans have not been analyzed or prepared for the 2014-2020 period.

Liberty asked why supply planning does not include a longer-term view. The response was that a high degree of uncertainty exists in the DSO load forecasts. A high degree of uncertainty related to the future impact of DSM and energy efficiency was also emphasized.

The difficulty of forecasting load requirements, including DSM and energy efficiency impacts, do not present sound reasons to avoid long-term planning; to the contrary, they underscore the importance of examining future uncertainties and considering responsive actions carefully. 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 meeting them. The portfolio plan determines the resource requirement levels required (incorporating DSM and energy efficiency), and the types of supply resources and mix of resources that will be most effective given forecasted energy markets. Analyzing various resource mixes under changing load and market conditions will stimulate thought regarding how to make progress toward long-term objectives.

6. The examination of alternative capacity resources and markets to meet NYISO UCAP requirements has not been sufficiently aggressive. *(Recommendation #3)*

The NYISO's UCAP capacity requirement is [redacted] in total for NYSEG and RG&E, depending on the time of year. The companies plan to meet all future capacity requirements by purchasing [redacted]-year capacity contracts in the bi-lateral markets, or from NYISO if such a product becomes available. The companies should also consider buying capacity from these sources, as well as from generators or marketers, through RFP solicitation processes. IUSA observes that a capacity surplus currently exists in the region. The surplus has driven down capacity prices at NYISO for the region. The companies should evaluate all feasible alternatives and a variety of durations to its existing plan for capacity purchases, and include them in its plan for optimal portfolio management.

7. Organization and staffing are consistent with that of effectively managed electric supply procurement groups.

The energy supply group is organized in a manner that is commensurate with the effective planning, analysis, and procurement of electric capacity and energy. Key managers' experience levels compare favorably with those generally found in the industry in similar positions. Staffing levels are adequate, and individual staff members are generally well qualified.

The energy trading desk in Binghamton is managed by competent procurement specialists that are seasoned and knowledgeable. The companies have developed all of the prerequisite capabilities in terms of processes, procedures, software tools and skill sets. Procurement decisions were clearly documented and were subject to appropriate levels of management approvals. The documentation of the Company's code of conduct was appropriate, no violations of code of conduct were identified and adequate controls were in place to detect and report such activities. Upper management review of trading activities appeared adequate and well documented.

8. Daily electric scheduling and bidding operations are effectively conducted with appropriate risk management and approval processes.

NYSEG and RG&E have well-defined daily processes and operations for scheduling electric purchases and for bidding for NYISO spot electricity. The trading desk is operated within normal protocols. A code of conduct has been implemented and followed. Adequate risk management procedures are in place to separate the functions and activities of the front and back office operations. The documentation of the risk management procedures and protocol was appropriate and consistent with other utility trading groups.

The control and management of transactional records is also well managed, and redundant computer systems were established to protect information from risk of loss. The Allegro software is state-of-the-art and provides the Company with appropriate monitoring and tracking capabilities. The separation of front and back office activities was adhered to and properly managed. The risk management protocols relative to energy trading and hedging were well documented.

While it is a very minor point, Liberty observed that the monitors used by the traders were of the old tube type that had to be propped up on boxes of paper in order for the trading floor to be able to see them. In itself, this is a minor inadequacy; however, it seems indicative of a less than sophisticated operation.

9. Electric procurement operations do not have a comprehensive and clearly documented process and procedures manual. *(Recommendation #4)*

The electric trading desk does not have a detailed process and procedures manual. The companies have developed a detailed day-ahead scheduling checklist that walks through each process that needs to be accomplished throughout the day. However, the companies do not have documented procedures, processes, controls and limitations for all processes in one manual. Documentation of these important processes would provide a reference manual for employees, which is especially important if there is turnover in the department. Detailed guidelines, controls and procedures should also be documented so that the processes may be properly audited by internal auditors.

Appropriate documentation of the processes, procedures and policies should be in place for this complex and important operation. The risk management processes have a detail procedural manual, for instance. Similar documentation should be in place for the procurement operations.

10. Executive committee oversight of the New York companies' risk management processes and credit evaluations are inappropriately located in Spain. *(Recommendation #5)*

The Risk Management Oversight Committee ("RMOC") is a working risk committee, and is not an executive-level committee. Company managers acknowledge that *there was not an executive* *risk management committee in either the utilities or at IUSA during Liberty's field work on this topic in April through July, 2011*. The IUSA holding company has a risk policy with limits and indicators on commodities and financial instruments, but does not have an executive risk committee. An executive risk committee should be in place in the U.S. at IUSA or at the New York utilities to provide formal executive management oversight of risk management activities for NYSEG and RG&E. The company reports that an executive risk committee was established at IUSA in November, 2011.

Iberdrola SA has an executive risk committee at the top holding company level. A monthly risk meeting is held with the SA CFO and risk managers from around the world. The IUSA risk director participates by video conference monthly, and travels to Spain for meetings twice per year. Liberty believes that such an organization structure results in risk management not being controlled by Company executives in New York, and that decision making is too far removed from the actual risks that confront the utilities.

Company management also reports that Iberdrola SA (Spain) risk management performs some of the counterparty credit analysis for supply procurement for the New York companies and sends reports to the New York operations. Liberty believes that all of the tracking and credit evaluation of the NYSEG and RG&E counterparties should be performed by analysts in the U.S. and not in Spain so that the analysis of counterparties is more timely and specific to those companies that IUSA does business with.

11. Risk management operates pursuant to a well-structured program with established and enforced policies and procedures and independent oversight.

The New York companies have a well-defined working energy risk-management structure, with the RMOC and appropriate risk policies, procedures and manuals in place. Everyday risk management is performed by a small risk management group whose charge is to enforce risk-management policies and procedures in place at the trading operations floor.

The billing and transaction risk management operations related to electric procurement are located at the Kirkwood facility in Binghamton and report to the VP-Energy Supply. This department's functions include electric and gas invoicing, deal confirmation management, credit and collateral management, internal IT support and SOX compliance. The function of billing and risk management appears to be standard for back-office responsibilities.

Oversight of these functions is the responsibility of the risk manager, who provides an appropriately independent review of transactions, oversight of counterparty credit worthiness, compliance checking for the code of conduct and the review of software tools. The risk management organization is appropriately separate from that of the transaction risk management operations.

12. Internal Auditing has not tested the electric procurement decisions and risk management decision-making processes. *(Recommendation #6)*

Internal audits of the electric procurement functions have been limited to testing performed on key controls over financial reporting in accordance with Sabanes-Oxley section 404. From January 1, 2009 to date, Internal auditing has not audited the decisions that are made on a daily basis by electric supply that determine which energy sources are used, the volumes of purchases, daily energy price bidding to the NYISO, purchases of hedges and other supply decision processes. Liberty did not find any audits of these latter activities from January 2009 to present.

The electric procurement decisions result in energy costs that are passed to DSO/VPO customers of over [redacted] million annually, which represents one of the largest expenditure areas for NYSEG and RG&E. The decisions made in signing electric bilateral contracts, the daily dispatch and scheduling of contracted and NYISO power, buying capacity contracts, and making spot purchases and sales are crucial and inherently risky processes. These decision processes require regular auditing and vigilance, as they constitute one of the greatest areas of risk. Liberty believes that this function requires frequent and regular audits, in order to assure compliance with procedures and to look for any errors or malfeasance.

D. Recommendations

1. **Develop a comprehensive long-term portfolio management plan with quantified goals and objectives to optimize the electric resource portfolio and related hedging plans.** *(Conclusions #1, #2, #4, and #5)*

The companies should develop a long-term plan for electric portfolio management that considers the electric resource options available, including energy alternatives and physical or financial hedging, as one package. The entire portfolio management for electric procurement should be optimized as one package, with the most effective mix of electric supply resources and hedging. Most importantly, the plan should include quantified overall goals and objectives for the portfolio, which should focus on minimizing volatility (CoV) and energy cost.

Optimizing supply portfolio management first includes the analysis of all market resources, considering a variety of instruments and durations to determine a target portfolio. Such an analysis should include long-term simulation of various mixes of market alternatives, with the goal of determining the optimum portfolio that best minimizes the volatility and cost of the DSO energy supply. The companies should hire an outside consultant to assist in performing the analysis, which should be based on a Monte Carlo simulation to determine the optimum portfolio of energy and hedging instruments.

The current electric hedging program should be analyzed as part of the electric resources considered in determining the optimum total portfolio. Price volatility should be targeted within an acceptable range that is consistent with NYPSC requirements. The companies should determine the pricing of the entire spectrum of market alternatives for energy and for physical and financial hedging as inputs to the analysis of an optimal portfolio. These instruments and their durations and pricing should be tested by probabilistic simulation modeling under a wide range of potential market conditions to ensure acceptable results in potentially volatile future markets.

An optimized portfolio management plan should also include a much longer planning horizon than the companies currently consider. The companies currently do not extend their electric resource planning beyond [redacted] years, or [redacted]. Liberty believes that an optimized portfolio management plan should include 10 years of resource plans to match refined 10-year load forecasts in providing a consistent long-term planning horizon for electric resources. The long-term portfolio plan provides the structure and resource components on a conceptual and targeted basis; the actual acquisition of resources should be performed through RFP processes and through other purchases to meet optimized portfolio targets.

An optimized portfolio management analysis and plan would provide the Company and the NYPSC with a commonly understood and systematic process for identifying and managing future electric supply resources. The companies should include the NYPSC Staff in the process to a greater degree than currently, performing the analysis annually and regularly presenting results to and discussing with Staff. The optimum plan should be commonly understood by both the companies and the Staff as the plan that minimizes DSO volatility and costs and should be executed by the companies.

Liberty recognizes that the optimum portfolio plan may include some components that are longer in duration than [redacted] years, and that such longer-term instruments entail some risk of future rate recovery. The optimum portfolio plan analysis should provide clear reasoning that the portfolio components should result in minimized volatility and costs, based on the best information available and the simulation analysis, which takes varying future market results into account. Of course, there are no guarantees that the future electric markets will cause all portfolio components to result in the lowest cost. As part of their annual presentation of the optimum portfolio plan to the NYPSC Staff, the companies should ask for such recovery assurance before entering into any longer-term components that are part of the portfolio plan.

2. **Conduct market solicitations for electric energy resources through RFP processes and implement any alternatives identified as superior to the existing plan of energy and hedging instrument purchases.** *(Conclusion #3)*

The companies should begin soliciting and evaluating all reasonable alternatives in the marketplace for the acquisition of energy and related hedging instruments. The companies have not considered formally soliciting purchased power contracts, physical hedges or other energy supply alternatives that may be available in the market. While the amounts of RFP-generated purchases and their durations should eventually be determined by the optimum portfolio analysis in Recommendation #1, an RFP process for energy and for physical or financial hedges related to that energy should be initiated as soon as possible. The two companies have contracts ending in 2011 of 782 MW of capacity and energy from NYPA and Nine Mile 2. Six-month and monthly capacity prices have recently plunged, signaling a market oversupply situation. The conditions for a successful market solicitation are currently favorable.

3. **Conduct market solicitations for electric capacity resources through RFP processes and implement any alternatives identified as superior to the existing plan of capacity purchases.** *(Conclusion #3, #6)*

The companies should begin soliciting and evaluating all reasonable alternatives in the marketplace for the acquisition of capacity. The company has been buying bi-lateral capacity contracts through its current UCAP capacity purchasing processes. The companies should consider other market alternatives and durations for meeting UCAP capacity requirements beyond its current practice of [redacted] capacity purchases with durations of [redacted] years. Given the probable oversupply of regional generating capacity, there is no reason, in our view, to not intensely explore all options for buying capacity through RFP processes, which should be initiated as soon as possible. The companies should evaluate all feasible alternatives to its existing sources for capacity purchases, and implement new sources and instruments when they are superior.

4. **Document processes, procedures, and guidelines for electric supply and scheduling.** *(Conclusion #9)*

The companies should document the important electric procurement procedures in a manual that may be used by both employees and by auditors. The dollar volume and importance of the electric procurement processes requires detailed documentation, reviews, and controls.

5. **An executive risk management committee should be formed at IUSA that oversees the risk functions and the RMOC and has executive responsibility for risk management.** *(Conclusion #10)*

An executive risk committee should be established in the U.S. at IUSA to provide formal executive management oversight of risk management activities for NYSEG and RG&E. Risk management activities for the New York companies should be controlled by company executives in the U.S., and not Spain. The executive decision making for risk management should be in the U.S. and be under the management of U.S. executives that are close to the actual risks that confront the utilities.

All of the tracking and credit evaluation of the NYSEG and RG&E counterparties should also be performed by analysts in the U.S. and not in Spain.

6. **Internal Auditing should schedule audits of electric procurements, documentation for entering into capacity supply contracts, and daily purchases.** *(Conclusion #12)*

Internal Auditing should audit the electric procurement operations and contracting made by electric supply on a regular basis. Electric procurements result in energy costs that are passed to customers that represent one of the largest expenditure areas and a large operational risk area. Electric energy purchases, as well as contracting for related hedging, should be audited. Procurement operations and processes for capacity contracts to meet UCAP requirements should also be examined.

Electric procurements that occur on a daily basis should be audited. The daily scheduling of contracted resources and making spot capacity and energy purchases are crucial and inherently risky processes. These daily processes require regular auditing and vigilance, as they constitute one of the greatest areas of risk to the Company. Liberty believes that this function requires frequent and regular audits, in order to assure the most attractive electric sourcing and to look for any errors or malfeasance.

Supply Procurement – Gas

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IX. Supply Procurement - Gas

This section addresses the gas supply procurement and related matters at NYSEG and RG&E. Generally, those activities are consolidated for the two Companies, although they may be performed by different individuals within the same group. The activities include:

- Organization and Staffing
- Controls, including purchasing, hedging, and auditing
- Commodity procurement - purchasing, local production, and price risk management
- Capacity and storage contracts, balancing and secondary market activities
- Gas control and dispatch
- Design day (peak load) forecasting
- Short-term (one-to-five day) forecasting
- Competitive markets and retail access
- Metering and measurement.

A. Background

The criteria by which Liberty evaluated the gas supply procurement function included the following:

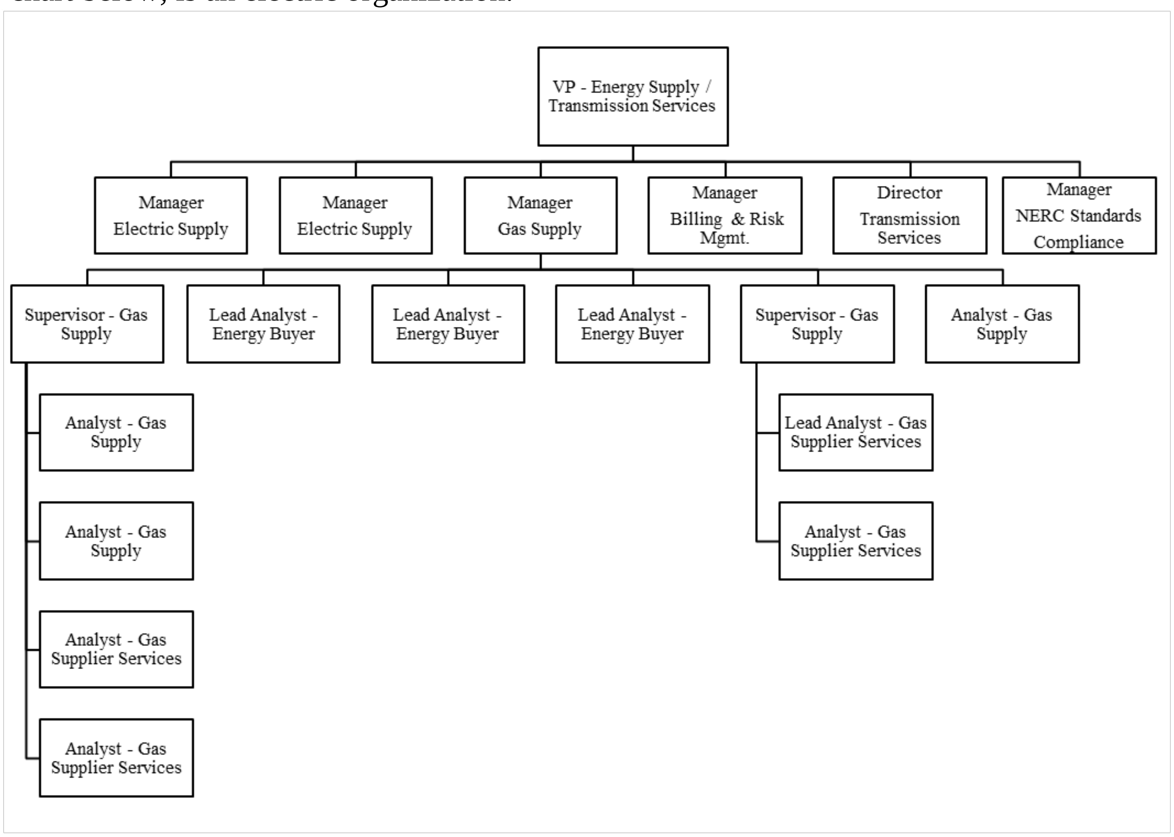
- The organization structure should be consistent with established mission, goals and objectives of gas procurement groups.
- There should be adequate coordination with other corporate departments involved in or supporting gas procurement activities.
- Key managers' experience levels should be consistent with those generally found in the industry in similar positions.
- Internal measurement systems should address performance quality on a comprehensive, ongoing basis.
- Approval processes should be consistent with the magnitude and risk of commitments involved and with processes applicable to other, major corporate commitments.
- Gas procurement policies and procedures should be consistent with work requirements and marketing objectives.
- There should be well-defined record creation and maintenance objectives and requirements.
- Documentation of procurement actions should be adequate to support regulatory oversight and review.
- Capacity contracts should be consistent with quality and reliability objectives.
- The Companies should promote the identification and use of sufficient numbers and types of vendors to meet needs.
- There should exist appropriate efforts to identify and establish alternate sources of supply.
- There should be a close fit between the capacity profile and load duration curves.
- The interests of on-system customers should be the predominant drivers of policies and procedures for operation of the Companies' capacity portfolios.
- Performance should be consistent with supply plans and supply asset specifications.
- There should be aggressive marketing of unutilized assets.

- Objectives for purchasing and price risk management activities should be clear, comprehensive, and supportive of utility needs.
- There should be a strong focus on liquid, transparent markets in gas procurement and price risk management.
- There should exist a sufficient number of suppliers identified and pre-qualified to meet likely short-term or emergency needs.
- There should be adequate information maintained for identified and pre-qualified vendors.
- Bid evaluations, including application of specific criteria, weightings, responsiveness, and supplier performance history should be conducted with analytical rigor and without bias.
- Metering and testing programs should conform to industry standards.
- Balancing strategy and practices should be fair to each customer class.

B. Findings

1. Organization and Staffing

The Gas Supply group is a 13 person group reporting to the Manager of Gas Supply, who reports to the Vice President of Energy Supply and Transmission services. The entire group is located in one office in the Kirkwood General Office Building in Binghamton. With the exception of Gas Supply, which is a gas-only group, and Billing & Risk Management, which handles that function for both the electric and gas services, the Energy Supply & Transmission Services, depicted in the chart below, is an electric organization.



The primary functions of the Gas Supply group include:

- Gas commodity procurement
- Supply asset procurement (capacity, storage, and peaking assets)
- Commodity procurement, including commodity price risk management
- Short-term (one-to-five day) forecasting
- Transportation scheduling
- Gas retail access program execution and oversight.

The Gas Supply group interacts with other groups on a regular basis:

- It provides the daily forecast (one-to-five day forecast to the Gas Control Center (GCC) for gas dispatch. The GCC is physically located in the Energy Center in Binghamton, and organizationally located under the Electric Control Center, which is in the same building.
- It receives the one-to-five year sales and revenue forecasts from Regulatory Strategy/OPCO Regulatory group.
- It implements the hedging program.
- It buys gas for the Allegany electric generating plant, but does not buy for or have any relationship to the marketing affiliates, Energetix and NYSEG Solutions, other than as ESCOs operating on the RG&E and NYSEG systems.

2. Controls

a. Gas purchasing controls

Iberdrola's most recent procedure for gas supply (known internally as "Cycle 9") was most recently revised on December 31, 2010. It describes the procedures and controls for the procurement of flowing gas and for gas injected into and withdrawn from company-owned or contracted storage facilities. The procedure also includes procedures and controls for calculating, billing and recording off-system sales. The procedure identifies the responsibilities of the front, middle, and back offices within the energy supply department. It also references the following procedures and plans:

- The energy supply department standards and procedures manual, for both electric and gas supply and related risk management, which is available electronically to all energy supply personnel
- The energy supply department disaster recovery (business continuity) plan
- The natural gas risk management acquisition policy.

All three of the above policies and plans are maintained by the Manager of Billing and Risk Management, and are to be updated annually if necessary.

The procedures reference the various approved contracts, periodic reports, forms, transaction tickets, nomination forms, variance reports, and journal entries. The procedure further describes the *Allegro* application system, which is used by Energy Supply to record gas purchases, both physical and financial, pipeline transactions, gas supply and transportation vendor invoices, and to track counterparty credit.

The procedures also describe various activities including:

- Preparation of annual, monthly, and five-day forecasts
- Procurement from vendors
- Contract authorization approval
- Counterparty credit exposure
- Gas purchasing
- Gas hedging
- Gas nominations
- Gas measurement
- Counterparties' invoices
- Processing and reconciliation of journal entries operation, backup, and security for the Allegro system.

The gas storage procedures (Cycle 11), also most recently revised December 31, 2010, include the procedures and controls for tracking, receiving, storing, and withdrawing gas from storage facilities. This procedure also describes the front, middle, and back office responsibilities and references various manuals and documents, including:

- The energy supply department standards and procedures manual
- The various leased storage contracts in effect
- Various periodic reports
- Use of the Allegro application system.

The storage procedures describe the following activities:

- Gas injections, including measurement
- Storage agreements
- Gas withdrawals including measurement
- Cost of injections of storage gas
- Valuation of withdrawals of storage gas
- Reconciliations and journal entries
- Physical inventory of gas
- The Allegro system, as described in the gas purchasing procedures.

The Companies have an *Energy Supply Risk Management Procedures Manual*, most recently updated in May 2011, which specifies requirements for gas procurement, including:

- Authorized transaction types and limits
- The natural gas hedging policy
- Long term interruptible sales service agreements
- Supply to the RG&E-owned Allegheny power plant
- Counterparty limits and contractual provisions
- Roles and responsibilities of Gas Supply, Billing, and Risk Management personnel
- Policies and procedures for gas purchasing, sales and capacity release, nominations, third party portfolio management, pipeline transmission and storage contracts, and retail access.

b. Hedging Controls

Iberdrola's natural gas risk management acquisition policy addresses the use of hedging instruments by NYSEG and RG&E. The currently effective policy is dated September 2003, with various approvals up to and including the president of the Companies. The policy states, as its primary objective, the reduction in price volatility for customers using financial instruments and storage. The program is to be conducted under the oversight of the risk management oversight committee.

The program guidelines call for hedging approximately 60 percent of the total expected winter requirement for each of the Companies for the coming winter by November 1. Approximately 30% of the annual purchases will be hedged on a rolling basis. The hedging program can include storage, long-term supply contracts, purchases of forward physical supplies, purchases of NYMEX future contracts, and purchases of over-the-counter financial instruments. The financial transactions include 12 month and 16 month future contracts, split 75 percent and 25 percent, respectively. The policy states that the financial transactions are to be done primarily with futures contracts on the NYMEX.

The risk management oversight committee (RMOC) has the responsibility for oversight over the Companies' electric and gas hedging activities. The RMOC meets monthly and keeps meeting minutes. Members include the following:

- Manager of the Energy Supply Risk Management
- Manager of Electric Supply
- Manager of Internal Audit
- Director of Risk Management
- Manager of Billing and Risk Management
- Manager of Derivative Accounting
- Manager of Energy Supply (Gas)
- Vice president of Energy Supply.

Agenda items typically include updates on some or all of the following: credit issues, billing issues associated with the ISO, audits/SOX, gas supply, and electric supply.

c. Audits

A number of tests of internal controls and audits of the gas supply process and related matters have been conducted over the years 2006 through 2010, including:

- Reviews of the gas optimization agreement[1] with BP Energy Company (January 2007, June 2008)
- Reviews of the gas optimization agreement with Shell Energy North America (November 2008, December 2009, July 2010)
- Review of the implementation of the Allegro Transaction Management System (April 2007)

[1] All the gas optimization agreements included all Energy East Companies at the time, NYSEG, RG&E, Berkshire gas Company, Connecticut Natural Gas company, and Southern Connecticut Natural Gas.

- Reviews of gas purchases for NYSEG and RG&E for each year during the period
- Reviews of gas in storage for NYSEG and RG&E for each year during the period.

The audits did not identify any material discrepancies. Minor issues were identified from time to time, with remediation plans developed and implemented.

3. Commodity Procurement

Gas supply is responsible for all gas that shows up at the city gates for both NYSEG and RG&E. Gas supply also has some responsibility for Maine Natural Gas gas operations and New Hampshire propane operations, and for RG&E's Allegany electric plant. Gas supply previously included procurement for the two Connecticut companies and Berkshire gas, which have been sold recently by Iberdrola. On average, approximately 50 percent of the gas is transportation gas; on the design day, transportation is approximately 75 to 80 percent of the total, because no interruptible sales gas is flowing.

a. Purchasing

Annually, Gas Supply sends out a non-binding Request for Quote (RFQ) for winter supply (November through March) to 14 suppliers. Winning bidders are required to have NAESB agreements in place by a specified date in order to secure contracts. Since the Companies have a number of receipt points, bidders are asked to fill out spreadsheets indicating which of those points they are prepared to provide supply to and at what prices, separately for base load and swing gas. The NYSEG Winter 2010-11 RFQ requested bids to meet specified monthly firm base load requirements at three different receipt points on the Dominion Pipeline and monthly firm swing load requirements at seven different points on the Columbia Gulf, Dominion, Empire, Columbia, Texas Gas and Tennessee pipelines.[2] The RG&E Winter 2010-11 RFQ requested bids to meet specified monthly base load at seven different receipt points on the Tennessee, Dominion, and TransCanada pipelines and swing supplies at three different points on the Dominion, TransCanada and Empire pipelines.[3] Eleven suppliers submitted bids.

Bids are summarized and evaluated on a spreadsheet with a recommendation from the Lead Analyst, who prepares the evaluation, to the Manager - Energy Supply (Gas). Winning bidders are notified via recorded phone line or e-mail. For the Winter 2010-11, NYSEG bought baseload supply from two vendors, and swing from five vendors, while RG&E bought baseload from three vendors and swing from three. Overall, the Companies purchased under contract from nine different vendors in total.

Typically, baseload gas is priced based upon indices for the specific receipt points (e.g., NYMEX closing monthly price plus an adder) and swing gas is priced at Gas Daily price "flat" or plus an adder.

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[2] NYSEG's receipt points include Columbia Gulf Mainline, Columbia Gas Appalachia Pool, Dominion South Point, Lebanon Hub, Tennessee 500 Leg Pool, Texas Gas Carthage Hub, Texas Gas Zone SL Pool, Texas Gas Zone 1 Pool and Iroquois Waddington.
[3] RG&E receipt points include Dominion South Point, Dominion North Point, Lebanon Hub, Texas Gas Carthage Hub, Texas Gas Zone SL Pool, Texas Gas Zone 1 Pool, and Union Dawn.

Gas Supply looks for diversification of supply among counterparties but does not have a specific rule specifying diversity criteria.

b. Local production

Iberdrola and its predecessor companies have a long history with local producers supplying gas from the Trenton – Black River formation and from the Elmira area supplied through Corning gas. In 2009, local production contributed approximately 2.3 percent of NYSEG total requirements, and some 0.1 percent of RG&E total requirements. In view of the limited contribution to RG&E's supply, the remainder of this discussion will focus on NYSEG.

To date, NYSEG has considered all local production as interruptible due to reliability issues or the inability of NYSEG and the developers to come to an agreement for firm flows under an agreed-upon pricing structure. Over the period 2003 - 2008, all local producers have interrupted flows either for operational issues or pricing issues, i.e., producers felt they got better prices from non-NYSEG buyers. Therefore, NYSEG has fully backed up all local production.

In a 2007 Order, the Commission directed each LDC with local production connected directly to its system to file a plan, in its next major rate case filing, for use of local production as upstream capacity and as a replacement for capacity provided by the LDC. The Commission stated that ... *The plan should include required procedures, rules and practices for an interconnection and any operational balancing requirements needed to ensure the reliability of this gas source as an interstate pipeline replacement.*

The NYSEG/RG&E Local Production Plan was filed in its 2009 rate case. The Companies agreed that local production, from both deeper in the Trenton-Black River formation and Marcellus Shale, coupled with local area storage, has the potential to displace some pipeline capacity. While New York State has not reached a decision with respect to drilling into the Marcellus Shale formation, Pennsylvania is undergoing active development, and NYSEG has the ability to move some of that gas to its system.

The Company proposed a new local production area, LPA-1, which comprised the Elmira distribution system, and initially was planned to displace 20,000 Dt/day of upstream capacity. If and when New York State allows drilling into Marcellus Shale, NYSEG foresees the potential for additional local production areas, with the City of Binghamton as the likely next area of opportunity.

c. Price Risk Management (Hedging)

The Companies engage in two sets of activities which tend to manage commodity price risk and price volatility, physical storage of gas and financial hedging. Storage is primarily intended to ensure availability of gas during the winter season, with the added benefit of mitigating pricing levels and pricing volatility. Financial hedging, as used by the Companies, is solely intended to mitigate price volatility, and is done almost exclusively through NYMEX futures contracts.

The Companies' policy calls for hedging of approximately [redacted] percent of the winter requirement, which equates to approximately 30 percent of the annual requirement, through storage and financial instruments by November 1, with the specific stated goal of mitigating price volatility.

The table below shows the portfolio mix, forecast and actual, of financially hedged, and market price gas purchased by the Companies for the 2009 - 2010 winter season (Nov - March). Market prices are indexed to NYMEX, for monthly purchases, or Gas Daily or spot prices for swing gas.

Commodity Pricing Basis 2009 - 2010 Winter

Company	Pricing Mechanism	% of Portfolio		Average Price /Dth		
		Plan	Actual	Plan	Actual	Plan less Actual
RG&E	Physical Hedges	[redacted]	[redacted]	$5.58	$5.28	-5.4%
	Financial Hedges	[redacted]	[redacted]	$7.45	$7.45	0.0%
	Market Prices	[redacted]	[redacted]	$5.67	$6.69	18.0%
NYSEG	Physical Hedges	[redacted]	[redacted]	$5.56	$5.75	3.4%
	Financial Hedges	[redacted]	[redacted]	$7.95	$7.95	0.0%
	Market Prices	[redacted]	[redacted]	$5.71	$7.01	22.8%

The pricing results indicate that over the storage injection season, actual volumes of gas purchased under the various mechanisms were fairly close to forecast, with the exception of NYSEG storage (physically hedged) gas. Since financial hedges are purchased [redacted] in advance, and storage gas is injected from April through October, any adjustments to the forecast or weather-driven changes must be addressed through changes to the volumes of market priced gas.

Prices of gas injected into storage were somewhat lower than forecast for RG&E and somewhat higher for NYSEG. That they are different is not unexpected, because RG&E leans heavily on Canadian supply and NYSEG on Appalachian and Gulf supply. The financial hedges work out exactly as forecast since the financial instruments have locked in those prices. Market prices turned out to be approximately 20 percent higher than forecast.

The Companies purchase [redacted] month and [redacted] month futures contracts, on a weekly basis to reduce the impact of intra-month price volatility, [redacted]. The program ties back to an analysis of the Companies' hedging programs from January 2001 through April 2003 and earlier studies, which were incorporated into the *Natural Gas Risk Management Policy* approved in September 2003. The table below shows the purchasing pattern for futures contracts for the 2009 - 2010 winter referred to above, using hypothetical hedged volumes for illustrative purposes.

Financial Hedging Volumes - Pattern of Purchase

Winter Month	Hedged Volume	[redacted] Month Hedges	[redacted] Month Hedges
Nov 2009	A	[redacted]	[redacted]
Dec 2009	B	[redacted]	[redacted]
Jan 2010	C	[redacted]	[redacted]
Feb 2010	D	[redacted]	[redacted]
Mar 2010	E	[redacted]	[redacted]

Until early 2011, the Companies had included summer storage injections as part of the hedging program. In March 2011, PSC Staff advised the Companies that ... *Staff believes that the cost of hedging storage gas outweighs any perceived benefits, and therefore is recommending that all gas utilities stop hedging storage gas as soon as possible.* Staff further observed that ... *In the current environment of relatively stable prices, hedging more than 60% of total winter firm load imposes additional costs on ratepayers without associated benefits.*[4] Staff asked the Companies to notify it of their concurrence with both directives or to explain in detail any alternative approach and quantify the associated benefits to customers of that approach.

The Companies responded that while they could not validate Staff's view of the current pricing environment, they would adopt Staff's recommendations.[5] Subsequently, those decisions were incorporated into the Companies' activities.

4. Capacity and Storage Contracts

a. Pipeline Capacity and Storage Contracts

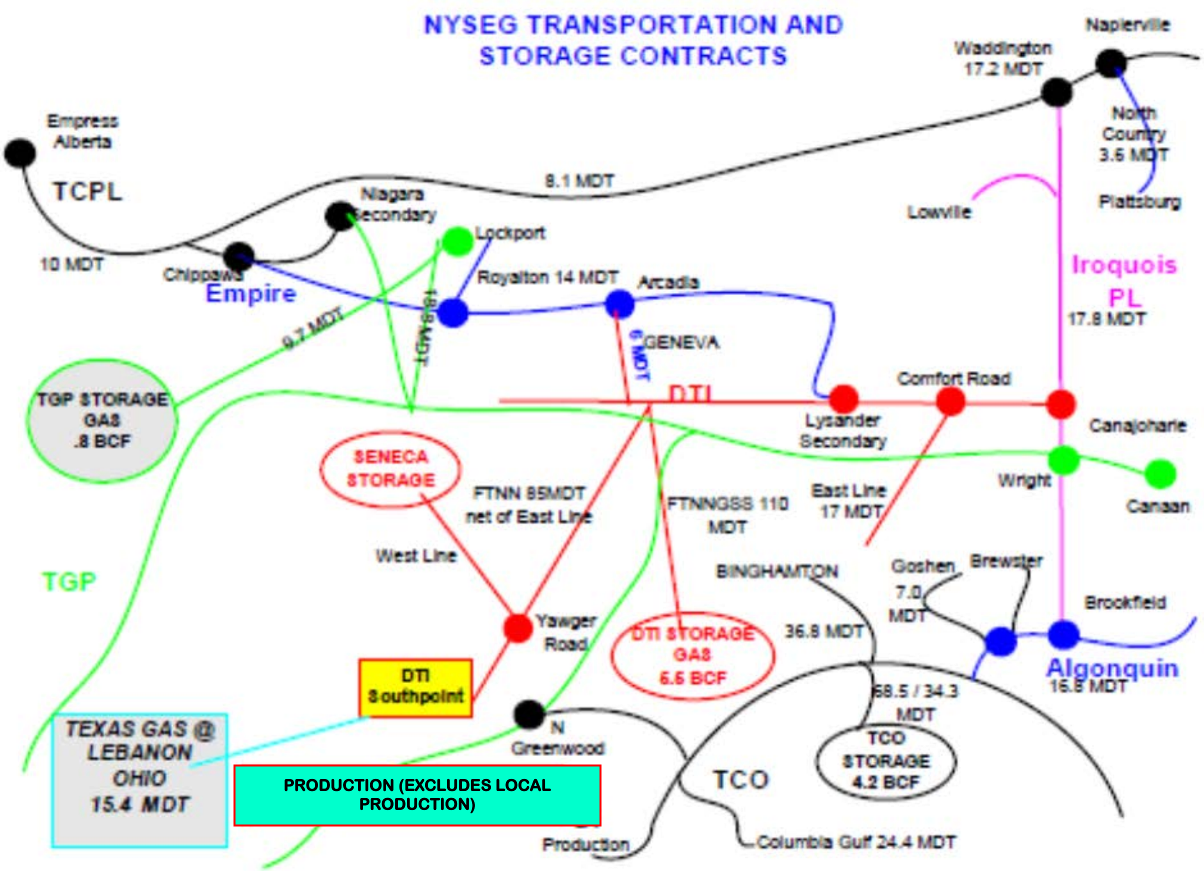
The companies are served by a total of 6 major citygate pipelines, 2 upstream pipelines, and 7 storage fields[6] as follows:

NYSEG Contracts:

- Algonquin (Citygate)
- Columbia (Citygate)
- Dominion (Citygate)
- Empire (Citygate)
- Iroquois (Citygate)
- Tennessee (Citygate)
- North Country (Citygate)
- Texas Gas (Upstream)
- TransCanada Pipeline (Upstream)
- DTI GSS Swing Storage (integrated with DTI pipeline network)
- DTI GSS Lockport Storage (integrated with DTI pipeline network)
- Columbia (TCO) FSS Swing Storage (integrated with Columbia pipeline network)
- Tennessee FS Storage (integrated with Tennessee pipeline network)
- Seneca Storage Facility (Watkins Glen, NY).

The schematic below shows the configuration and capacities of NYSEG's pipeline capacity and storage contracts.

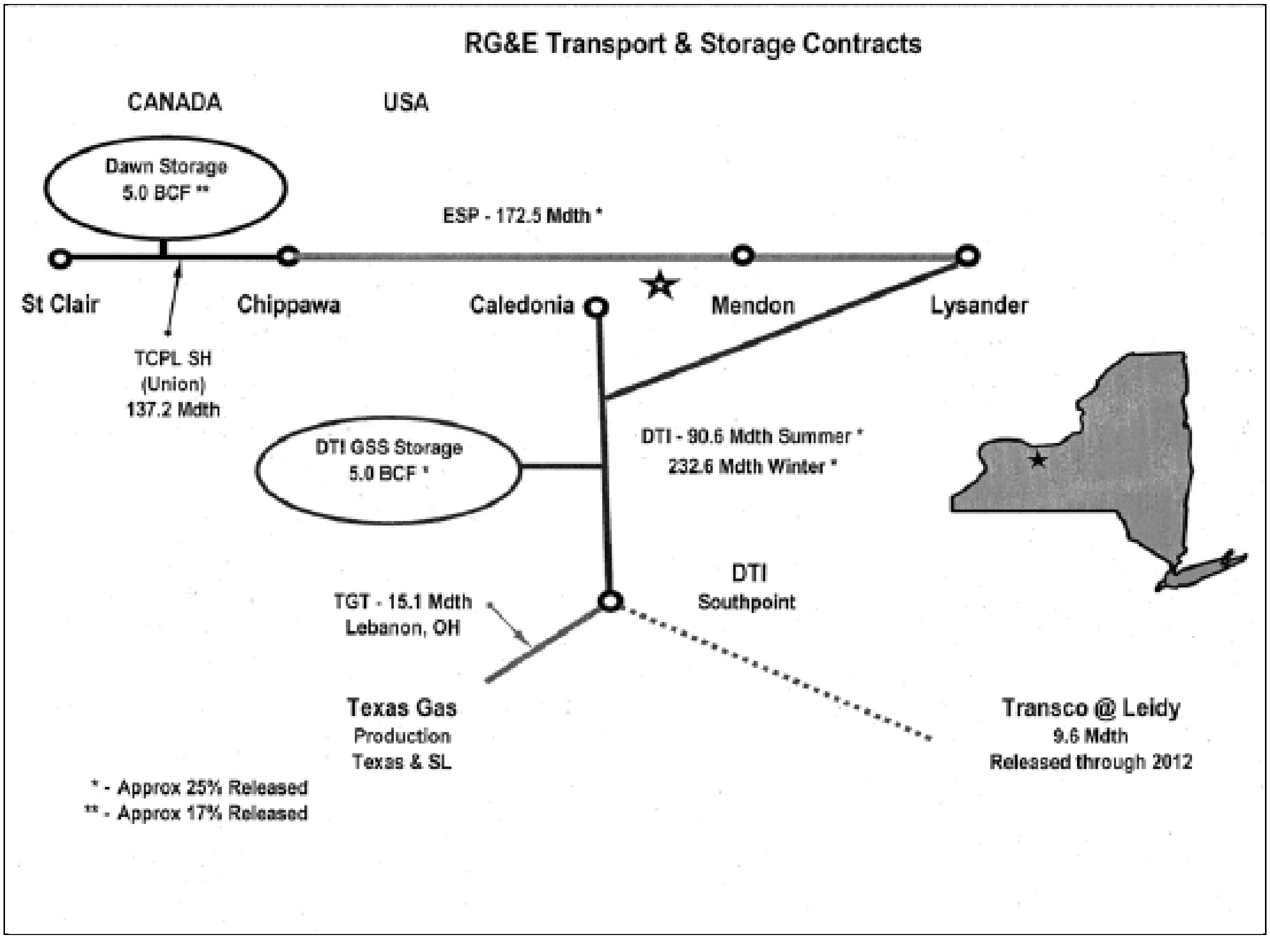
[4] Correspondence PSC Staff to NYSEG and RG&E, March 31, 2011
[5] Correspondence NYSEG and RG&E to PSC Staff, April 15, 2011
[6] Storage field, as used here, may refer to storage capacity provided by an integrated system or one discrete facility.



RG&E Contracts:

- Dominion (Citygate)
- Empire (Citygate)
- Texas Gas (Upstream)
- TransCanada Pipeline (Upstream)
- DTI GSS Storage (integrated with DTI pipeline network)
- Tenaska Dawn Storage (part of Tenaska asset-backed package).

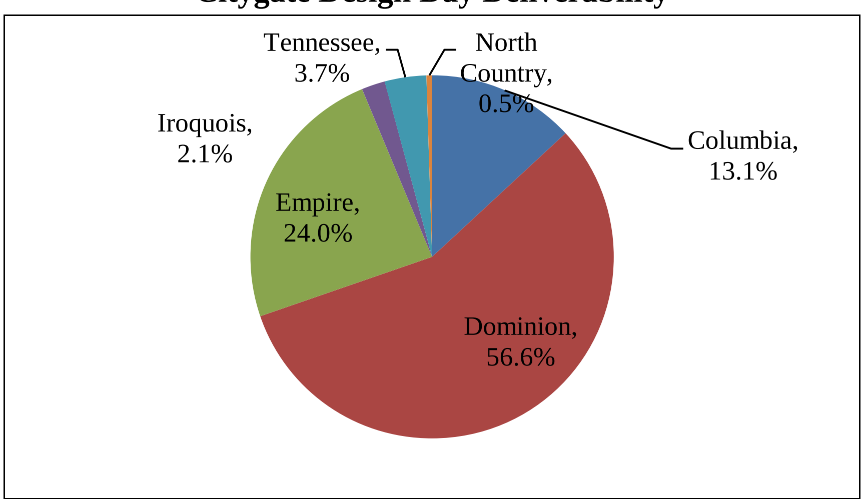
The schematic below shows the configuration of RG&E's pipeline and storage contracts.



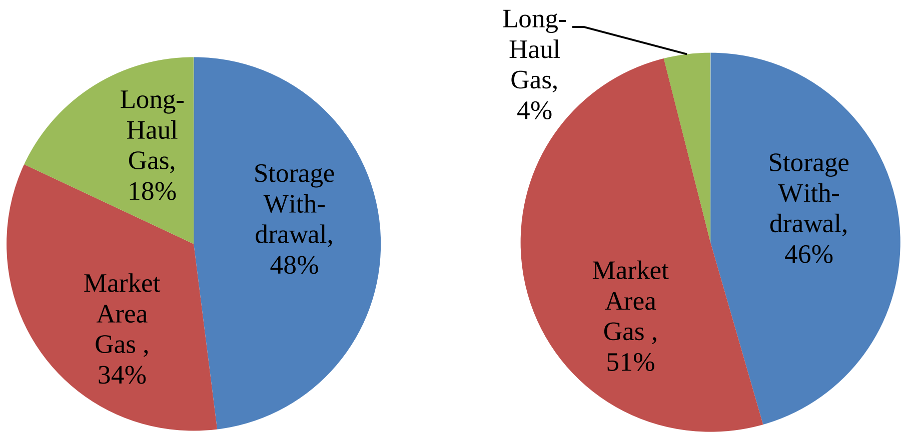
b. Citygate Deliverability

The charts below show the design day citygate deliverability for the two Companies combined, followed by design day resources for each Company:

Citygate Design Day Deliverability



NYSEG and RG&E Design Day Resources



The following two tables show the number of specific contracts by citygate and upstream pipeline and the expiration dates of those pipelines.

Major RG&E Transportation Contract Expiration Dates
As of March 31, 2011

Pipeline	*Term or Expiration Date	Citygate or Upstream Contract
Dominion Transmission, Inc.	3/31/2015	Citygate
	3/31/2015	Citygate
	3/31/2011	Citygate
Empire State Pipeline	10/31/2013	Citygate
	11/30/2011*	Citygate
Fillmore Gas	03/31/11E	Citygate
Texas Gas Transmission, LLC	10/31/2012	Upstream
	10/31/2012	Upstream
Transco	10/31/2012	Upstream
TransCanada Pipelines Ltd.	10/31/2011	Upstream
	10/31/2011	Upstream
Union Gas Limited	03/31/2011E*	Upstream

* Interruptible E: Evergreen contract provision

Major NYSEG Transportation Contract Expiration Dates
As of March 31, 2011

Pipeline	*Term or Expiration Date	Citygate or Upstream Contract
Algonquin Gas Transmission	10/31/2013E	Citygate
	12/31/2011E	Citygate
	12/31/2011E	Citygate
Dominion Transmission, Inc.	03/31/2017E	Citygate
	03/31/2017E	Citygate
	03/31/2015E	Citygate
	03/31/2017E	Citygate
	03/31/2017E	Citygate
	03/31/2012	Citygate
	07/17/2011E*	Citygate
	07/30/2011E*	Citygate
Columbia Gas Transmission	10/31/2019E	Citygate
	01/31/2011E*	Citygate
	03/31/2020E	Citygate
Columbia Gulf Transmission	12/31/2011E*	Citygate
Corning Natural Gas Corp	3/31/2011	Citygate
Empire State Pipeline Co	10/31/2013	Citygate
	10/31/2011E*	Citygate
Iroquois Gas Transmission	11/1/2017	Citygate
	12/31/2011E*	Citygate
National Fuel Gas Supply	05/01/2014E*	Citygate
Niagara Mohawk Power Corp.	10/31/2011E	Citygate
North Country Gas Pipeline	12/21/2013E	Citygate
Orange & Rockland Utilities	10/31/2011E	Citygate
	11/30/2011E*	Citygate
Tennessee Gas Pipeline Co.	10/31/2016E	Citygate
	10/31/2012	Citygate
	10/31/2012	Citygate
	07/01/2011E*	Citygate
	07/13/2011E*	Citygate
	10/31/2016E	Citygate
Columbia Gulf Transmission	10/31/2019E	Upstream
TransCanada Pipeline Ltd.	10/31/2011	Upstream
	10/31/2011	Upstream
	10/31/2011	Upstream
	07/04/2011E*	Upstream
Williams Gas Pipeline - South Central	12/11/2011E*	Upstream
	11/30/2011E*	Upstream

* Interruptible E: Evergreen contract provision

c. Balancing

Buyers and sellers must ensure the matching between volumes scheduled ("nominated"), purchased and delivered at the various delivery and receipt points. That matching is referred to as balancing.

As explained above, the Companies take deliveries from and deliver to a number of pipelines, as well as several LDCs. Balancing provisions are addressed in the tariffs of each Company. The balancing calculations are performed daily, and imbalances are generally addressed through one of the following mechanisms:

- Cumulative during the month and cashed out at month's end
- Cumulative during the month and carried over at month's end
- Cumulative during the month; negative imbalances cashed out, positive imbalances carried over at month's end
- Cumulative during the month, addressed through nominations the next month
- Daily balancing performed using storage service.

Imbalances are calculated as the difference between nominations and metered measurement at the citygates, except in the case of one LDC, where it is calculated as the difference in flows between two metering points.

d. Secondary Market Activities

Because LDCs can never match exactly supply with demand, with weather the dominant contributor to that mismatching, they must err on the side of reliability of supply. Thus, they frequently have some level of assets, in the form of pipeline capacity and gas commodity, which are considered excess. Those assets are typically leased or sold to third parties through capacity releases and off-system sales.[7]

Capacity is also released through the Retail Access program. This is not excess, but rather, capacity needed to serve customers buying commodity from non-utility suppliers who have elected to or are mandated to purchase utility capacity.

Gas Supply reviews its loads annually, seasonally and monthly to determine the volumes that may be released. Information as to potential releases is then communicated to the Companies' regular counterparties. The gas buyers are in regular communication with counterparties with approved NAESB agreements, through telephone, e-mail and instant messaging. All releases are conducted on the relevant pipeline's electronic bulletin board. Capacity releases under the Retail Access program are sold at full tariff rate, while all other releases are at market prices, e.g., whatever prospective purchasers will bid. Off system sales are made at market prices.

Under the terms of the Gas Cost Incentive Mechanism (GCIM) in the most recent Commission rate case order, all revenues from Retail Access capacity releases flow to customers. Revenues

[7]Also known as bundled sales, i.e., capacity bundled with commodity.

received by the Companies from other releases and off system net sales are shared 85%/15% between customers and shareholders, respectively.

Transactions are tracked through the Company's Allegro transaction capture and management system, which records and tracks physical and financial purchases and sales, monthly checkouts with counterparties, and tracks counterparty contracts and credit.

The tables below show the Companies' capacity release and off-system sales activities for the years 2007 through 2010.

NYSEG Capacity Releases				
Year	**Approx # Transactions**	**Total Demand Cost**	**Total Credit**	**% of Tariff Rate Realized**
2007	855	$2,675,531	$2,077,673	77.7%
2008	1093	$3,471,372	$2,998,294	86.4%
2009	1876	$5,070,265	$4,597,140	90.7%
2010	2274	$6,030,501	$5,277,553	87.5%
RG&E Capacity Releases				
Year	**Approx # Transactions**	**Total Demand Cost**	**Total Credit**	**% of Tariff Rate Realized**
2007	256	$38,957,046	$27,403,282	70.3%
2008	245	$29,962,383	$21,663,187	72.3%
2009	156	$10,404,656	$10,324,259	99.2%
2010	156	$11,955,978	$11,875,475	99.3%

NYSEG Off System Sales				
Year	**# Transactions**	**Total Cost**	**Total Revs**	**Net Profit (Loss)**
2007	53	$10,644,940	$11,431,438	$786,498
2008	334	$10,500,979	$11,274,881	$773,902
2009	377	$10,129,099	$11,565,654	$1,436,555
2010	545	$14,686,138	$16,364,393	$1,678,255
RG&E Off System Sales				
Year	**# Transactions**	**Total Cost**	**Total Revs**	**Net Profit (Loss)**
2007	8	$263,009	$274,133	$11,124
2008	1	$3,954	$3,798	-$156
2009	11	$247,755	$371,308	$123,553
2010	28	$2,498,810	$2,581,820	$83,010

The Companies have engaged in various asset management arrangements over the last several years, previously with Coral Energy Holding, LP and currently with Tenaska Marketing Canada. The Gas Portfolio Optimization Agreement with Coral was a three-year contract for all five

Energy East Gas Companies at the time, which terminated on March 31, 2010, and which provided for Coral to optimize the entire portfolios of the Companies. It provided for a 90/10 sharing of net savings between the Companies and Coral. The Coral arrangement replaced an earlier three-year “Alliance” with BP Energy Company, which expired on March 31, 2007, and was the third and final in a series of contracts with BP.

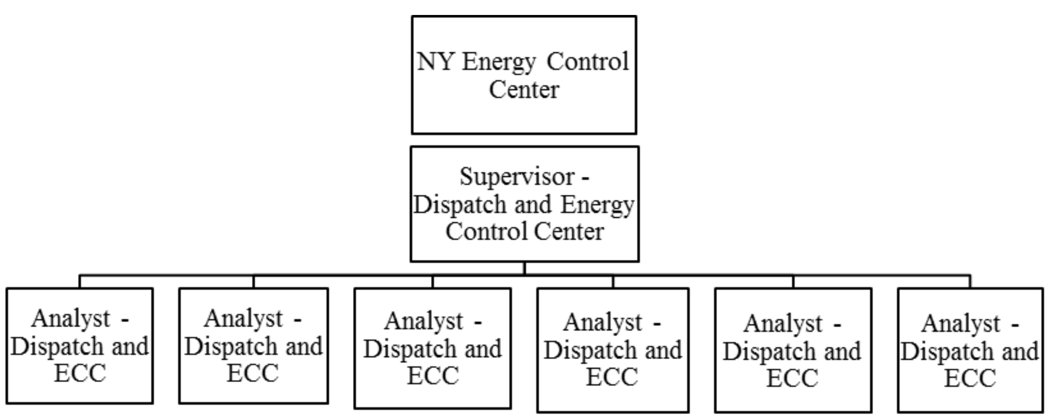
Coral was selected via a competitive bidding process. The Companies solicited bids from 16 potential bidders, of which 14 responded. After evaluation, Iberdrola developed a short list of two finalists and ultimately selected Coral.

Subsequently, after Iberdrola sold the two Connecticut gas companies, Connecticut Natural Gas and Southern Connecticut Gas, the Companies decided to limit their next optimization agreement to their Canadian assets. Bids were received from six bidders. Only two bidders submitted bids that fully addressed the Companies' entire Canadian portfolio. Of the two, Tenaska Marketing Canada offered the better sharing arrangement [redacted] of net proceeds between the Companies and Tenaska) and was selected. An agreement was put in place for the period April 1, 2010 through October 31, 2011, with two successive one-year automatic renewals. Either party may terminate the agreement with notice delivered six months prior to the termination date.

5. Gas Control

The GCC is physically located in the Binghamton Energy Control Center building, in the same structure, but physically independent from and remote from the Electric Control Center. A backup control center is located at the Kirkwood facility, having been very recently relocated from another facility close to the primary GCC when threatened by Tropical Storm Irene.

The Supervisor of the GCC reports to the supervisor of the Electric (nominally Energy) Control Center, who reports to the Director of System Operations in Maine. The organization and staffing of the GCC is depicted in the organization chart below:



The GCC receives data from remote terminal units (RTUs), at approximately 175 monitoring stations with approximately 1,300 sensors on the NYSEG system and 18 monitoring stations with approximately 620 sensors on the RG&E system.

The RTUs generally communicate hourly with the GCC via telephone land lines. Approximately 17 percent and 44 percent of the lines on the NYSEG and RG&E systems, respectively, are dedicated (leased) lines, and can use the dial-up network as backup. The remainder uses the telephone network with no backup lines. The Companies do not have backup communications systems for these data communications.

Most of the sensors involve pressure or temperature monitoring. In addition to the hourly communications, when conditions outside the alarm limits of the sensors are experienced, the RTUs will report in. On approximately 15 percent of the sensors, for each Company, the GCC can remotely adjust the set points for the sensors, i.e., they can change the setting that will trigger a notification. Generally, there is no other control that can be exercised by the GCC,[8] with two exceptions: the GCC can turn heaters on and off at RG&E's Mendon Station and can start and stop the compressors at NYSEG's Norwich compressor station.

6. Peak Load Forecasting - Design Day and Design Winter

Gas utilities typically design their portfolios to meet worst-case scenarios, known as the design day, the coldest possible calculated day, and design winter, the coldest possible calculated winter period from November through March. Gas load consists of non-temperature sensitive and temperature sensitive load. In LDCs such as NYSEG and RG&E, the winter heating load is the primary driver of and predictor of peak load.

NYSEG hired a consultant to perform a weather study in 1992. The result of that study was a report entitled "Recommended Normal and Design Day Weather Patterns," dated September 1992. The study examined 40 years of weather history for the years 1951 through 1991, and developed three weather cases, for normal, colder than normal, and warmer than normal weather in the Binghamton and Buffalo areas. The study concluded that NYSEG should design for a 75 heating degree day (HDD) design day. It found Buffalo weather to be somewhat warmer than Binghamton overall (8 percent warmer, based on HDDs for the 40 year period) but concluded that for purposes of planning and budgeting the Binghamton data could be substituted for the Buffalo data.

No additional weather studies have been performed subsequent to that time. Subsequently, the results of that study have been applied to the entire NYSEG and RG&E in the systems, with two minor exceptions. The Company departs from the study results only in the Plattsburgh area, where it uses 80 HDDs and the Brewster area, where it uses 65 HDDs. Those two areas represent a very small portion of the Companies' loads.

7. The One-to-Five Day Forecast

Gas Supply develops a one-to-five day forecast early every weekday morning for each load zone, seven for NYSEG and one for RG&E. The forecasts are based on next gas day (starting at 10 AM) and the following four days weather and HDD forecasts and a monthly regression analysis

[8] For example, there are no remotely operable valves or odorizors.

for each load zone, on a total load basis. The Companies use a weather service which provides to them weather information for five locations, Binghamton, Rochester, Buffalo, Poughkeepsie, and Burlington, VT.

The forecast is developed based on a regression analysis of data for the month based on historic data for the last three years. They had been using seven years historic data until recently, but reduced it based on their judgment of customer response to current economic conditions. For example, to develop the June 2011 forecast, they would analyze historic data from June 2008, June 2009 and 2010. This would result in a forecast day for June 2011 in the form of base load plus an HDD adjustment. That forecast day would be the starting point for developing the forecast for each day in June 2011.

After developing the forecast day, the Company does a "similar day" analysis using a spreadsheet program that searches a database to find historical days that exhibited similar weather characteristics to the forecast next day characteristics. Those characteristics include high and low temperatures and previous day high and low temperatures. The program evaluates and rates each of the four characteristics and creates a rank order of similar days. It then creates a table and graph of the hourly loads for the top five similar days.

The analyst then determines whether to adjust the zonal forecasts based on the similar day analysis as well as any known trends or changes on the system, and creates the final hourly zonal forecasts. The final forecast is then provided to the gas buyers and to gas control.

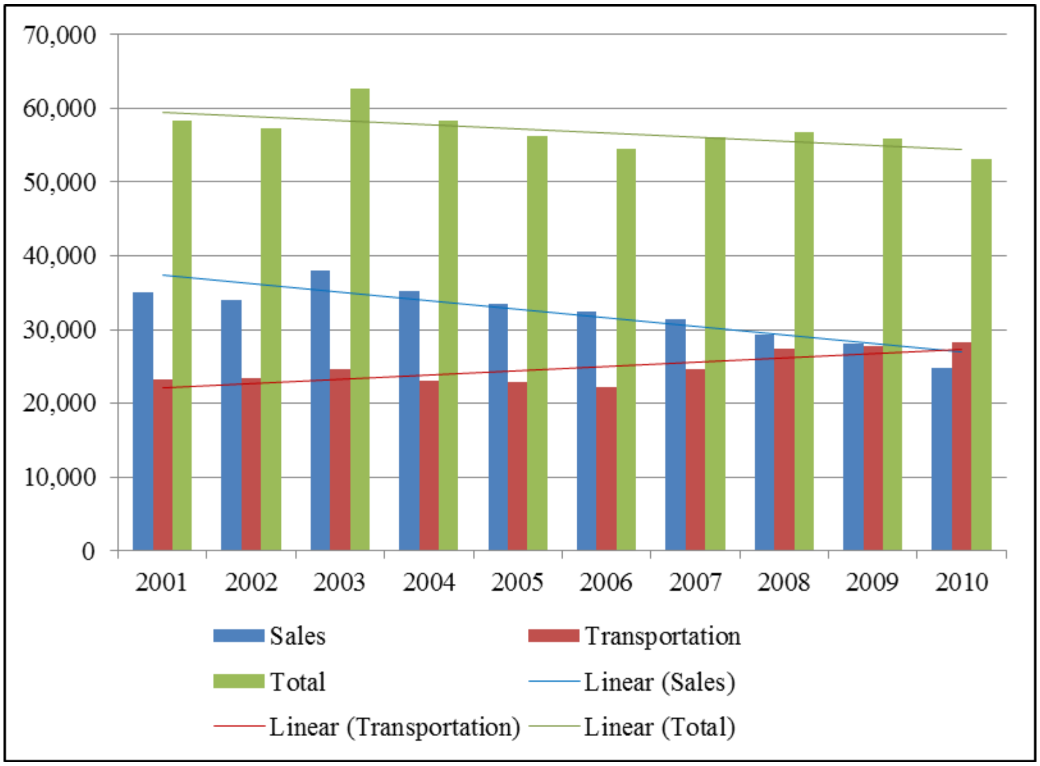
The model and approach does not explicitly consider wind or day of the week (e.g., weekday, weekend, and holiday). Those considerations are included on a judgmental basis by Gas Supply staff.

8. Competitive Markets and Retail Access

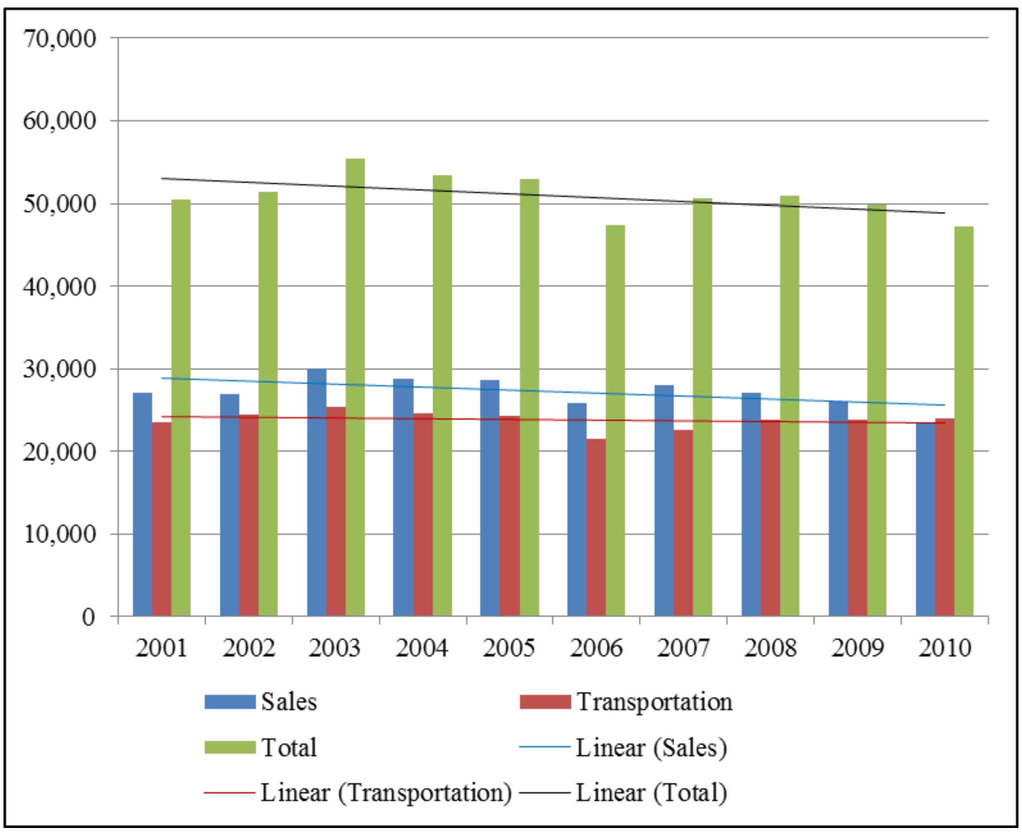
a. Market Penetration

The Companies' throughput includes both sales gas and transportation gas. The graphs below show throughput for each Company for the years 2001 through 2010, broken down by sales, transportation, and total. The bars represent actual data, while the trend lines represent a simple linear regression analysis of the data performed by Liberty.

NYSEG Throughput 2001 - 2010 (Mdt)

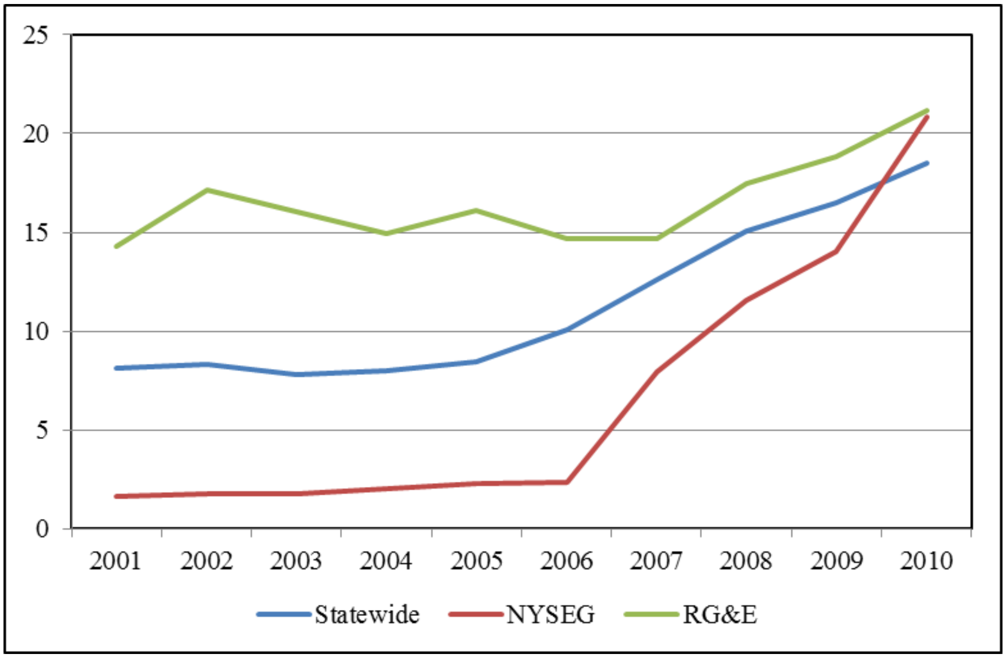


RG&E Throughput 2001 - 2010 (Mdt)



The Companies' ratios of sales to transportation gas have been influenced by the Commission's retail choice program. The following graph depicts the percent of customers taking transportation gas compared to sales gas (i.e., those buying gas commodity from the utility) for the same 10 year period.

Per Cent of Customers Taking Transportation Gas

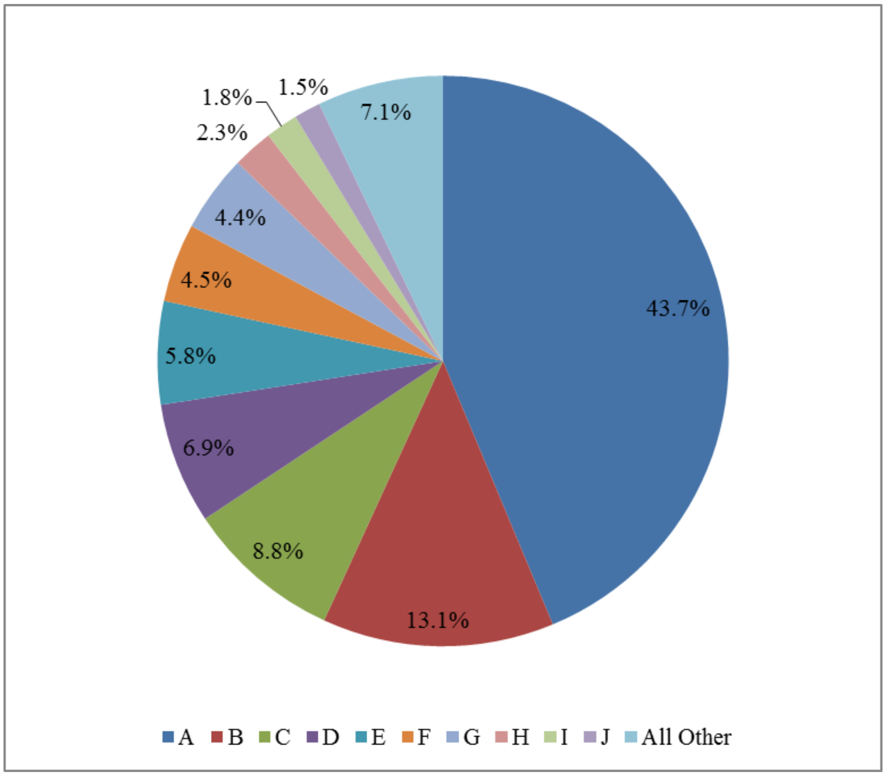


Both Companies have a substantial number of ESCOs doing business on their systems. The charts below show the distribution of numbers of customers and load among the roughly 20 percent of customers who have migrated from the Companies to ESCOs.

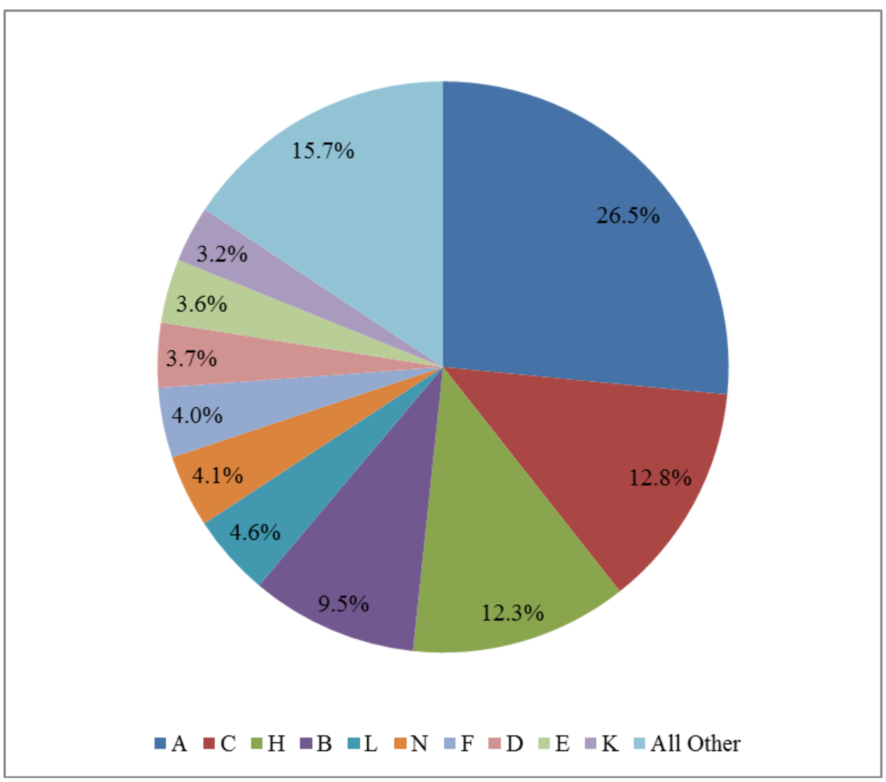
b. Market Share

The following charts depict the market share of the ESCOs serving the Companies, by percent of migrated customers and percent of migrated load. Names of ESCOs have not been specifically identified to protect competitively sensitive information.

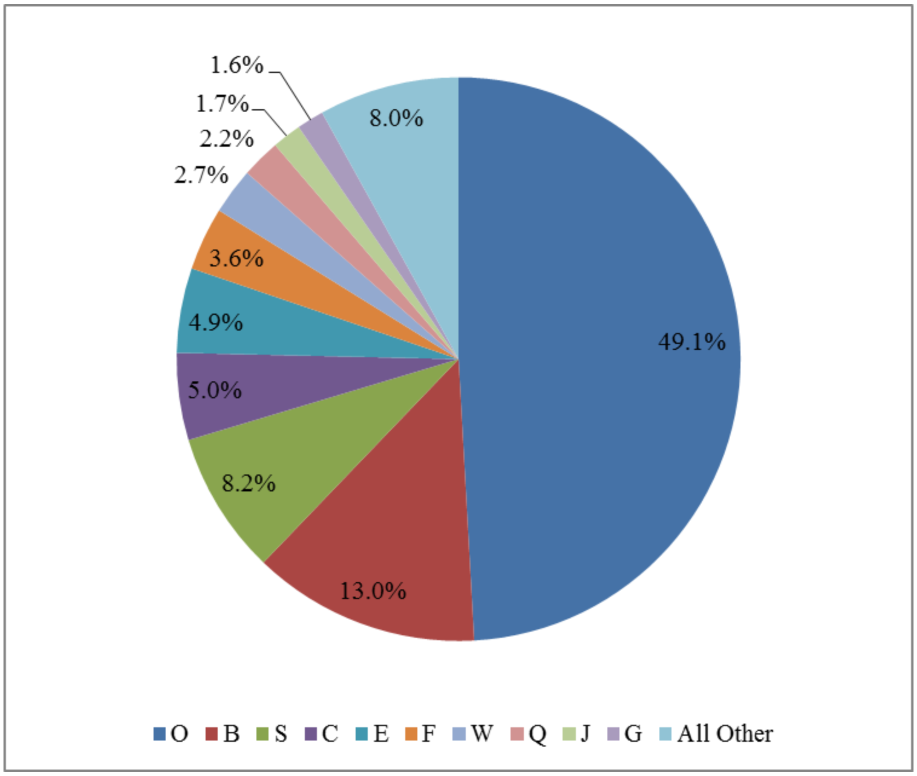
NYSEG - ESCO Market Share - % of Migrated Customers



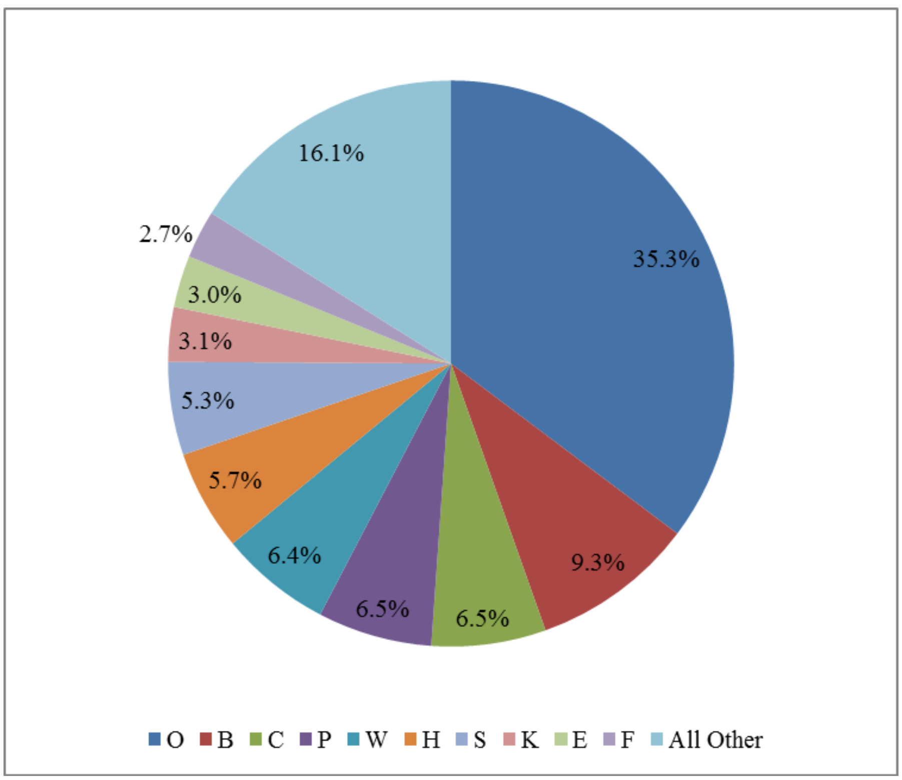
NYSEG ESCO Marketer Share - % of Migrated Load



RG&E - ESCO Market Share - % of Migrated Customers



RG&E ESCO Marketer Share - % of Migrated Load



c. Balancing of ESCO Supplies

The terms and conditions of the LDC - ESCO interface are contained in the *GTOP Manual*, the NYSEG/RG&E Gas Transportation Operating Procedures Manual, which describes the operating procedures of the Companies applicable to the Retail Access program, including balancing provisions.

Balancing is handled differently for Daily-Metered and Non-Daily Metered Customers. The Retail Access program, which is designed for small customers, therefore falls under the Non-Daily Metered provisions. Under those provisions, ESCOs on the NYSEG system are required to nominate and deliver to a designated delivery point(s) a predetermined daily aggregated volume (DAV). The DAV is determined by the Companies for each ESCO or pool of ESCOs based on the HDD forecast and average consumption estimates. ESCOs enter their nominations in the SmarTRAC system, (described in the next section) as described in the GTOP manual, using NAESB nomination rules.

ESCOs on the NYSEG system must take service under the "Non-Daily Metered Transportation Monthly Balancing" tariff, except for those who have opted for CSC balancing in the DTI pooling area. Handling of imbalances is described in the GTOP. Differences between an ESCO's DAV and its upstream deliveries are cashed out to the ESCO, based on a pricing index depending on the pipeline pooling area. Imbalances at the citygate of up to plus or minus 2% are cashed out at the average price of the index, plus pipeline variable and fuels costs. Negative imbalances greater than 2% are cashed at the same price plus $1.00 per therm under normal operating conditions, and $2.50 per therm during an Operational Flow Order (OFO). Positive imbalances are cashed out at $1 per therm less the above price, except during an OFO, when they are cashed out at $2.50 less the above price. The sum of the daily cashouts is a standard item on the ESCO bills.

d. Interface with ESCOs

The interface between the Companies and ESCOs providing gas to customers on the Companies' systems involves several different types of activities, the Retail Access electronic bulletin board (EBB), communications related to tariff matters, curtailments, if required, customer switching, and capacity and commodity recompilations associated with customer switching.

Business relations with the ESCOs are typically handled in the Supplier Relations group, which is housed in the Customer Service unit, while day-to-day interfaces are handled in Gas Supply.

Among the most labor-intensive activities are maintaining the EBB and handling customer switching. Many of the activities are performed manually, including handling customer switching from the LDCs to ESCOS, from ESCOs back to the LDCs, and among ESCOs, because the current system is not capable of processing all of the changes. Total numbers of customer switches have ranged as high as 5,000 per month. Many of the activities are lumped under the name SmarTRAC, which is actually a group of applications and systems that are only partially integrated. SmarTRAC was developed by NYSEG in 1998 and was expanded and modified on several occasions. SmarTRAC handles the following primary functions:

- Calculation of ESCOs' Pool Volumes
- Communications between the Companies and ESCOs

- Customer metered usage data
- Forecasting of daily and monthly volumes
- Managing imbalances
- Handling ESCO nominations
- Reporting
- Settlements and billing information

The existing SmarTRAC interfaces in various ways with the Allegro system, the SCADA system, the SAP Customer Care System, and the Metretek metering system.

In April 2011, Iberdrola issued an RFP for the functional design of a SmarTRAC system replacement, an application program used by the Companies and described as follows:

> *SmarTRAC is an application that is used at NYSEG and RG&E to manage all gas nominations, gas delivery, balancing, and settlement functions. It provides a web-based electronic bulletin board to facilitate interactions between the ESCOs (Energy Service Companies) and NYSEG/RG&E for third party gas transactions coming from our utility "city gate" (meaning where a pipeline meets our distribution lines) to the burner tip of the customer. NYSEG and RG&E each use a unique version of the SmarTRAC application; some business functionality is common to both Companies, other functionality is company specific. Neither version adequately covers all functionality required by the Business in today's Gas Retail Access environment. In addition, the existing applications are constructed with outdated and unsupported technologies.*
>
> *NYSEG and RG&E want to replace the existing SmarTRAC applications with a single application that encompasses all necessary business functionality for both companies, including numerous business tasks that are currently handled manually. Additionally, the replacement application must align with the up-to-date IT technology standards.*

Bids were received in May 2011, and a vendor was selected to perform the functional design of the system by year-end 2011 or early 2012. Iberdrola will then issue another RFP in the second quarter of 2012 for building the system, which is projected to go live in mid-2013. In the last rate case, the Commission Order allowed for up to $1.625 million for the project.

9. Metering and Measurement

The Companies' gas meters are subject to the requirements of New York State Regulations, specifically NYCRR Parts 226.8 and 226.9. Meter tests are performed in company-owned and operated meter shops, in the field or, for certain large turbine meters, returned to the manufacturer for testing. The Companies state that their shops and portable equipment, as well as those manufacturers to whom they return meters for testing, are certified by the NY PSC.

New meters are adjusted at the factory to a tolerance of plus or minus one percent, and are tested on a statistical sample basis by the Companies. Existing meters are tested on various bases depending on the type and/or age of the meter, as specified in Company procedures. Company procedures also call for gas volume correctors (for pressure and temperature variations) to be calibrated upon initial installation and annually thereafter. Fixed factor equipment, used where customers receive gas at higher than normal delivery pressure, is inspected annually.

10. Lost and Unaccounted for Gas

Lost and Unaccounted for gas is a catch-all gas accounting category which includes gas lost, gained, or consumed but not metered. Contributors to that account include, but are not necessarily limited to, leak losses, pipeline metering error, customer metering error, unmetered company use, theft, and energy to volumetric measurement conversion. The table below shows s the Lost and Unaccounted for percentages for the Companies for the five-year period 2006 through 2011.

Lost and Unaccounted for Gas Percentages 2006 - 2010

	Year (Ending 8/31)	Measured LAUF
NYSEG	2006	0.993
	2007	1.00258
	2008	0.99964
	2009	0.99772
	2010	0.99245
RG&E	2006	0.012568
	2007	0.021230
	2008	0.009704
	2009	0.006533
	2010	0.006756

C. Conclusions

Organization and Staffing

1. Organization and Staffing of the Gas Supply group is consistent with its mission, goal and objectives and industry practice.

The Gas Supply group is fully dedicated to Gas Supply functions, and performs no unrelated activities. The distribution of functions within the group reflects an evolved rather than a designed structure but reasonably accomplishes the necessary tasks. Liberty found the group to be generally similar to and consistent with those of other large LDCs.

2. Key managers are well qualified and experienced. However, the experience levels of other employees vary dramatically.

The two key managers in the group have broad and deep backgrounds in the gas business, as well as other utility experience. The backgrounds of the other employees vary widely. Excluding the two key managers, the distribution of direct or related experience breaks down as follows:

- 10+ years: 3 employees
- 3 - 5 years: 3 employees
- 1 year or less: 5 employees.

The high percentage of employees inexperienced in gas supply reflects, to a great extent, the recent high level of turnover at Iberdrola, particularly associated with the 2010 voluntary early retirement program and subsequent restructuring of various parts of the organization. At one point, the normal complement of three gas buyers, a front line function, was down to one buyer.

3. The staffing of the Gas Supply group is very lean and undercuts the ability to address matters beyond day-today operations. *(Recommendations #3 and 4)*

While the Gas Supply group is now fully staffed according to the corporate organization charts, it is a very lean group. This means that while the key managers are aware of weaknesses in the operation, (e.g., the outdated weather study and the shortcomings of the one-to-five day forecast, both discussed herein), there are neither the numbers nor skill levels of staff available to perform the required studies and analyses. Coupled with the shortage of experienced employees, this also means there is no backup for the key managers and minimal overall "bench depth" in the group.

Given the very large portion of the cost structure constituted by gas costs, Gas Supply is one of those organizational units that should err on the side of too many rather than too few staff members. It is a group that should leave no stone unturned in performing its functions, and to do so requires sufficient staff.

4. The organizational placement of Gas Supply within an otherwise all-electric unit tends to weaken the Companies' overall gas business. *(Chapter II, Recommendation #2)*

As shown in the organization chart earlier in this chapter, Gas Supply is one of six groups that reports to the Vice President, Energy Supply and Transmission Services. That position is staffed by an individual with an electric background, and four of the other five groups are electric-only groups. The fifth, Billing and Risk Management, performs both electric and gas functions. This organizational placement means that there is no review and sounding board for the Manager of Gas Supply by anyone well-versed in the gas business, and tends to inhibit the communications and coordination among gas groups in the Company.

Controls

5. Procurement policies and procedures are appropriate and consistent with work requirements.

The Company has a comprehensive and reasonably current set of policies and procedures addressing capacity and storage and hedging. Approval and signoff authorities are consistent with the magnitude and risk of commitments. The Company's Risk Management Oversight Committee exercises appropriate oversight over policies, procedures and program implementation of the gas risk management (hedging) program. The front, middle and back offices exhibit a good separation of functions and relationships. The Company conducts regular audits of gas supply procurement and the optimization agreements, and reviewed the performance of the Allegro transaction management system shortly after it was put into operation.

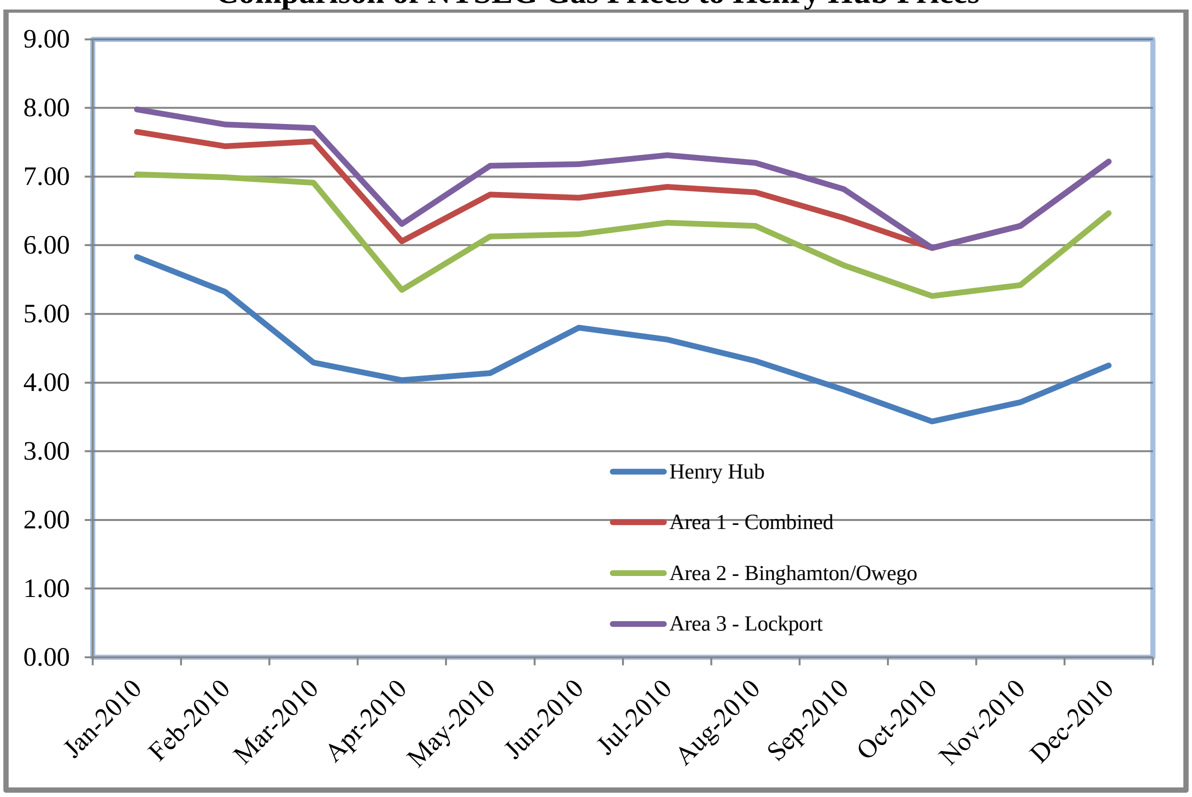
Commodity Procurement

6. Gas Supply has developed and implemented a reasonable strategy to balance reliability and cost.

Gas Supply purchases winter gas (November through March) on a formal RFP bid basis, and summer gas (April through September) on monthly and daily bases. The Company maintains a reasonable diversification of suppliers, in terms of sources of gas, numbers of firms, and pricing mechanisms. Commodity prices are all tied to indices at various price points for which standard index prices are developed and openly reported.

Liberty compared the cost of gas purchased by Iberdrola in 2010 for its three NYSEG zones with gas prices at the Henry Hub in Louisiana, the pricing point for NYMEX futures contract and considered the benchmark price for North American natural gas markets. The comparison is shown in the figure below.

Comparison of NYSEG Gas Prices to Henry Hub Prices



The differences between the benchmark Henry Hub price curve and the curves representing each Area price reflects the cost of transportation; i.e., moving the gas from the source to the citygates. As the three areas are served to a great extent by different pipelines and from different producing areas, the curves reflect the different cost structures of the pipelines and the different price indices.

Generally, the Area price curves follow the Henry Hub price curve, although the relationships are moderated by Iberdrola's use of physical hedging (storage) and financial hedges. Overall, Liberty found Iberdrola's commodity procurement practices and pricing structures to be typical of industry practice.

7. Gas Supply's RFP process for winter gas appears unbiased, with reasonable analytical rigor.

Gas Supply sends its RFP for winter supply to a number of suppliers. While the Company has agreements with approximately 50 suppliers, it makes an initial cut based upon past experience and knowledge of which companies are able to provide gas to its various locations, some of which are less liquid, at competitive prices. For the 2010 - 2011 winter, Gas Supply sent the RFP for both NYSEG and RG&E to 14 suppliers, of which 12 responded. Suppliers were free to bid to supply any or all of the requested receipt points.

An analyst in Gas Supply performed a comparative spreadsheet analysis of the bids, including compliance with delivery terms, price, flexibility, and any other special requirements or terms, and made a recommendation to the Manager of Gas Supply and the Vice President, Energy Supply and Transmission Services.

8. Local production has provided some value to date, and appears to offer very substantial value in the future if IUSA positions itself to maximize the potential benefits. *(Chapter VII, Recommendation # 1)*

NYSEG receives local production gas[9] from eight firms on its system. Local production represented about 2.9 percent (12,844 Dt) of NYSEG's firm peak day capacity for the 2010 – 2011 winter, but is considered interruptible and is not taken into account when determining ability to meet design day requirements. Thus, although the local production provides value in terms of lower cost because it does not include the cost of long haul transportation, the greater value of displacing pipeline capacity and storage is not realized. The local production is considered interruptible for two reasons -- production may be curtailed for operational reasons and producers may sell to buyers other than utilities. An examination of local production flows for a recent five-year period (2003 - 2008) shows that each local producer delivered no gas to NYSEG at some point during each of the five years.

New local production in the Elmira area in the near term, and Marcellus shale gas in the longer term, have the potential to change that, possibly very substantially. This gas is expected to be considered firm and will tend to bring down the cost of gas by reducing pipeline transportation costs.

Because it has a long history utilizing local production, the administrative infrastructure (procedures, standard TAP agreement, standard NAESB contract form, etc.) are already in place and are readily available for new local production.

9. The Companies' hedging program is designed to mitigate commodity price volatility, while avoiding the temptation to "beat the market."

[9] Local production gas on RG&E's system is minimal.

The Companies hedging program is specifically designed to mitigate price volatility, as stated in its policy statement, and to avoid the temptation of trying to beat the market. It involves [redacted]. The only discretion on the part of the buyer is with respect to spreading out purchases scheduled for a given month over that month.

This program approach is designed to comply with the Commission's policy statement on hedging, which requires LDCs to consider mitigation of price volatility as one criterion in designing their gas portfolios. The Companies' hedging program is discussed with Commission Staff annually at the winter supply review meetings.

Recently, Staff added additional conditions to the Companies' hedging programs. By letter dated March 31, 2011 PSC staff notified NYSEG, RG&E, and all other New York State gas utilities that they cease hedging the prices of storage gas. Staff stated that they believe that the cost of hedging storage gas *"… outweighs any perceived benefits, and therefore is recommending that all gas utilities stop hedging storage gas as soon as possible."* Staff requested that the company provide notification of its concurrence, or if not, to explain in detail why not and quantify the associated benefits to customers of its position.

Staff also stated that it believed that a utility's total gas hedging portfolio be limited to 60 percent of total normal winter firm load, and that hedging greater than 60 percent *"… imposes additional costs on ratepayers without associated benefits."* Staff further requested that the company notify it of the Company's concurrence, or if not to explain in detail why not and quantify the associated benefits to customers.

Certainly Liberty does not question Staff's authority to make such requests or the specific parameters identified by Staff. We note that Staff is, in effect, setting those parameters. Under the terms of the Commission policy statement, utilities have been directed to consider mitigation of gas volatility as one of the parameters they take into account when they buy gas. Mitigation of price volatility is not a cost reduction activity, but rather, protection against high levels of price swings. The benefits to customers by mitigating price swings are qualitative, and any attempts to quantify them are highly subjective. Upon receipt of the Staff letter, the utility is faced with the Hobson's choice of going along with Staff, or pursuing some other course of action which provides no financial gain to the company and which would require quantification where one is not possible with any degree of precision.

<u>Capacity and Storage Contracts</u>

10. The Companies' portfolios represent an effective diversity of pipelines, storages, and contract expirations.

The physical layouts of the Companies' service territories require a diversity of pipelines and storage, to a substantial extent due to the non-integrated nature of the systems. In addition to meeting the basic system requirements, Gas Supply has developed and maintained diversified portfolios of pipelines, storages, and contract expiration dates.

11. The Companies have been divesting upstream pipelines as pooling points become more liquid, which provides benefits by reducing gas costs and increasing flexibility.

Over time, natural gas pooling points have been moving downstream and have become more liquid, with the development of pricing index points at many of those locations. This has enabled LDCs to divest some of their upstream pipeline contracts and to purchase gas at the liquid points, thereby reducing pipeline capacity costs. Gas Supply has been doing so in recent years, and expects to continue to do so. Abilities were limited, particularly at RG&E, but long term contracts allow the current portfolio much more flexibility to sculpt contracts. Additional opportunities may be presented following the design day study discussed below.

12. Exploitation of Marcellus Shale and other indigenous sources appears to offer substantial potential for cost savings.

If and when New York State allows hydraulic fracturing in some areas of the state, NYSEG in particular appears to be strategically located to take advantage of such production.

Iberdrola has done some conceptual evaluation of the impacts of Marcellus Shale on the systems, but has not developed specific scenarios considering possible interconnections, supply volumes, pipeline capacity that may be displaced, and other parameters. This is an issue that is much larger than the Gas Supply Group and is addressed in Chapter VII, System Planning - Gas.

13. Data from the capacity releases and off-system sales activities indicates high levels of excess capacity in the past. *(Recommendation #3)*

Liberty examined capacity release and off-system sales data for the four-year period 2007 – 2010. During that time period, NYSEG's activities, measured by gross revenues, increased fairly dramatically. RG&E's activities, particularly capacity releases, decreased from a fairly high to a more moderate level.

Several factors contribute to those results, some of which have offsetting influences. First, Liberty concluded that the design day forecast for both Companies is too high, which would tend to produce a higher level of assets. When unused they are remarketed through capacity release and off-system sales. Second, Liberty found that the high turnover in staff in the Gas Supply group, particularly among gas buyers, resulted in a loss of experience, which would tend to decrease activity. Third, the Companies have been decontracting some assets, which would tend to make a lower level of assets available for remarketing. This is particularly true for RGE, which de-contracted some significant contracts in 2008, resulting in a dramatic decrease from 2008 to 2009. The results of the weather study and stability in gas buying staff should address these issues.

14. Citygate assets appear high based on an outdated and apparently high HDD calculation. *(Recommendation #3)*

The level of Citygate assets is appropriate based upon the Company's design day assumptions. However, as discussed below, Liberty believes those assumptions are premised on an outdated and geographically limited study and produce a higher than necessary asset requirement. If the design day requirement is lowered, that would enable a reduction in asset levels.

Gas Control and Dispatch

15. The Gas Control Center is understaffed in terms of both numbers and qualifications of personnel. (*Recommendation #11, Chapter II Recommendation #2)*

The GCC is the nerve center for the operation of an LDC's facilities. It is the location where system operating data comes in and where operating control takes place.

The GCC is understaffed, for the following reasons:

- On other than business day shifts, the standard staffing is one controller.
- The standard rotation includes all six qualified controllers. When a controller is out sick, on vacation, or absent for any other reason, the others need to fill in. As a result, there are times during business days when there is only one controller on duty.
- When one controller is on duty, if he becomes incapacitated for any reason, a period of time may go by before anyone notices.
- There is no backup supervisor. Other than the six qualified controllers, the only other person qualified is the supervisor. When she is unavailable, there is no qualified supervision available.

There is no manager, senior manager or officer in the chain of command with gas experience above the Supervisor of Gas Control. The supervisor reports to the Manager of Electric Control, who reports to the Director of (Electric) System Operations in Maine. That issue is addressed in Chapter II, Corporate Planning, wherein Liberty recommends consolidation of most gas activities into a gas business unit.

All training for controllers is on the job. There is no simulator available, and no emergency training other than that which may be encountered during the on-the-job training.

16. The Gas Control Center physical facilities are significantly deficient. (*Recommendation #2)*

The GCC is located on the main floor of the Energy Control Center building, in a warehouse-like environment. It is a long, relatively narrow space at one end of the building, with standard construction windows running the full length of the space and wrapping around the ends. There is one control desk with two control stations and one computer station located in the space, as well as several offices and meeting rooms. The GCC does not have any type of large, system-wide display board or large video display; the only displays are the control stations dual video desk monitors. This means that it is impossible to look at a display of any substantial portion of the system in any meaningful detail. In Liberty's experience, this is a highly unusual condition.

Should a number of alarms go off simultaneously on different parts of the system, they are all just flashing lines of data on the screen, with the controller left to visualize the pattern in his head. If, for example, a major pipeline loses pressure, the pattern of alarms might be difficult for a controller to recognize without a visual display of all the affected citygates.

The GCC is also physically isolated, so that should a problem develop within the GCC, there is no one nearby other than the personnel in the control center, which could be only one person.

17. The organizational location of the GCC under an otherwise all-electric organization appears to drive the neglect of the GCC. *(Recommendation #1 and #2)*

The Supervisor of the GCC reports to the supervisor of the Electric Control Center who reports to the Director of System Operations in Maine. System Operations is almost entirely an electric organization. Three of the four direct reports to the Director have electric-only responsibilities and the Supervisor of the ECC has an all-electric background.

The GCC's deficiencies stand in marked contrast to the Electric Control Center, which exhibits none of the staffing or physical facility deficiencies exhibited by the GCC, and which is currently updating its display board to a state-of-the-art video wall.

Design Day (Peak Load) Forecasting

18. The design day load forecast appears high. (*Recommendation #3)*

The level of assets (pipeline capacity, storage gas, peaking contracts, and local production), is based upon projected design day and design winter weather, the coldest day and coldest winter for which the available assets will be sufficient without curtailment of any firm customers. Those calculations are based on historic weather data. While the details of the methods applied vary across utilities, generally they rely upon a backward look at historic data for a period of at least a decade, and often several decades.

Iberdrola's design day traces back to a 1992 study that analyzed the coldest days in the Binghamton and Buffalo areas. That study determined the coldest day in the Binghamton area to be 75 heating degree days (HDDs) and 72 HDDs in the Buffalo area, based on a backward look at 40 years of historical data. It then recommended using the 75 HDD day for both. It was applied to the entire NYSEG service area, and then to the RG&E area as well.

With the exception of the northern part of the state, Binghamton is one of the coldest regions. Further, the application of the study ignores non-coincident peaks, which are likely a consideration given the broad geographic dispersion of the service territory. In addition, Iberdrola maintains a reserve margin tied to the 75 HDD level to handle balancing requirements and other variations. Historically, that margin was specified at 2 percent. In recent years, it has gradually been reduced, and is currently approximately 1.2 percent.

Liberty believes the 75 HDD plus reserve margin requirement is excessive, thereby incurring excessive costs for assets to meet that requirement, for the following reasons:

- Binghamton is one of the coldest areas in the state.
- The historical basis for the calculation is between 20 and 69 years old. The coldest days actually experienced during the study period were in 1980.
- The study does not reflect the last 20 years of data or any weather trends, older or more recent.
- The study does not consider the extent of non-coincident peaks, that is, peak loads in different service areas that occur at different times. If peaks are coincident, the Company must be prepared to meet the sum of the individual peaks. If peaks are non-coincident, the combined effect is less than the sum.

- Engineering states that it uses a design criterion of 70 HDDs. The basis for that criterion seems to be lost in history, although Engineering ties it back to the same study cited above. This may mean that 70 HDDs is a better criterion or that the systems have been under designed.

The recommended study will not require development of new weather data. Such data is readily available from several sources, including the National Oceanic and Atmospheric Administration (NOAA), and possibly from the weather services utilized by Iberdrola. NOAA maintains data from a variety of weather stations in New York State to reasonably model Iberdrola's service territory.

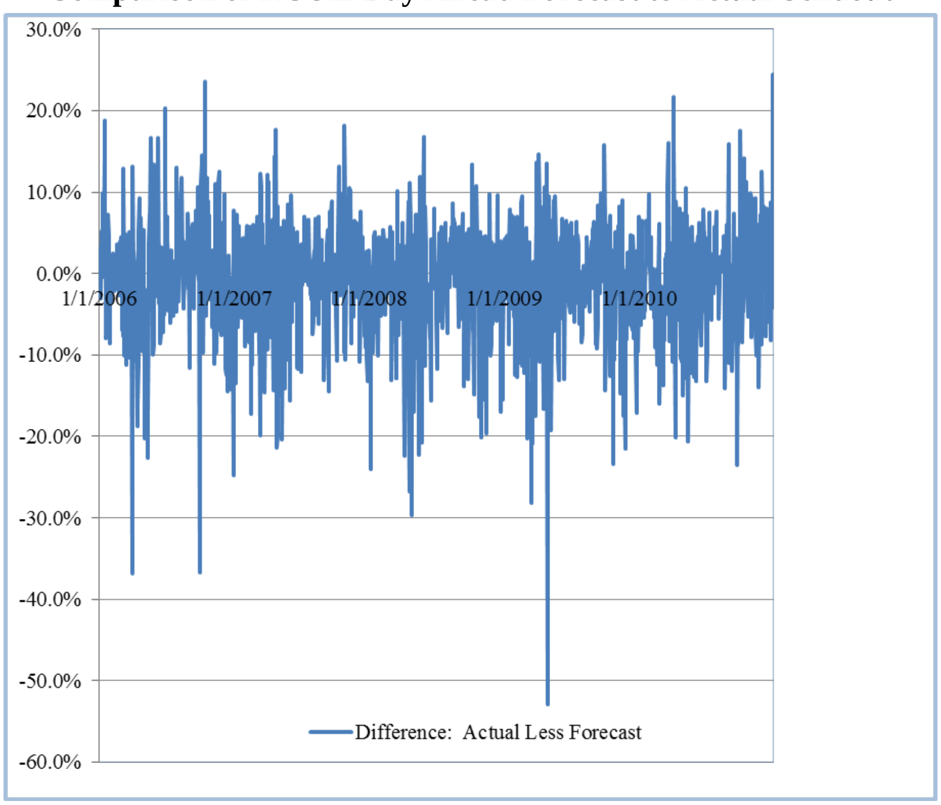
Short Term (One-to-Five Day) Forecasting

19. Short term forecasting is relatively unsophisticated, and exhibits a high level of inaccuracy. (*Recommendation #4)*

The one-to-five day forecast is performed each weekday morning, for each load zone and used by the GCC for gas dispatch. This daily exercise uses a spreadsheet model to develop base (non-heating) load plus a weather (HDD) assessment. After developing the next day requirements, the analyst then does a similar day comparison, looking for historical days with similar weather characteristics. The similar day selected is then used as a basis for the hourly loads.

The graph below compares RG&E day ahead forecast to actual sendout, showing the percent difference between the two. The data for NYSEG displays a similar range of differences.

Comparison of RG&E Day Ahead Forecast to Actual Sendout



Gas Supply indicates that they would like to see an accuracy level with a tolerance band of 2 percent. That is consistent with Liberty's view of reasonable industry practice. As may be seen from the above graph, performance is averaging in the plus or minus 5 percent range, but frequently exceeds plus or minus 10 percent.

Gas Supply looks at the variances from time to time, but does not formally track and analyze that data. Although Gas Supply is aware that performance is in need of improvement, there is no one available to perform the analysis and develop a more accurate model.

Competitive Markets and Retail Access

20. Retail Choice program is a mature program that has approached steady state at NYSEG and RG&E.

Full retail choice for all customers has been available in New York State and at the Companies for more than a decade. For the years 2001 through 2006, RG&E exhibited much better than average ESCO penetration, while NYSEG lagged considerably. Since that time, ESCO penetration has steadily increased, to the point where both Companies and the statewide average have converged at roughly 20 percent, and the trend indicates a gradual, continuing increase.

In Liberty's view, the program and process have matured and reached a steady state, with no dramatic changes absent a significant change in the regulatory approach or market conditions. The group of ESCOs is fairly stable, the bugs have been worked out of the GTOP, and the interface between ESCOs is smooth, albeit somewhat cumbersome for the Companies. That is expected to be remedied when the SmarTRAC project is complete and on line.

21. Administration of the retail choice program is generally fair and unbiased.

Liberty did not observe any evidence of favoritism among ESCOs, and found the disputed issues to be minimal. While the two affiliated ESCOs, Energetix and NYSEG Solutions, enjoy significant market share, Liberty's pie charts of market share earlier in this chapter show that no individual ESCOs have more than 50 percent share of either market, and there are significant numbers of participants.

Balancing

22. Balancing strategies and practices are cost-based and unbiased toward any customer groups.

Gas Supply tracks and administers the balancing provisions of its tariffs as specified in its procedures. The requirements are clearly spelled out in the GTOPs, including frequency and pricing of cashout methods.

Metering and Measurement

23. Metering and testing programs conform to industry standards.

The Companies procedures and standards are consistent with applicable New York State regulations. The Company states their shops and equipment are current in their approvals from the Commission, as are those of the shops which test their large meters.

24. The Companies' Lost and Unaccounted for gas percentages are very low.

An examination of LAUF percentages for the five-year period 2005 – 2010 indicates that NYSEG has been averaging about 1%, while RG&E has been averaging marginally above zero. These low figures are attributable, at least in part, to the Companies' fix-all-leaks policy and practices. However, RG&E's results in particular suggest that certain losses may be buried in other measurements and data. However, since the figures are very consistent year-to-year, any systemic errors are apparently stable and baked into the results of operations.

D. Recommendations

1. Upgrade the Gas Control Center personnel numbers and qualifications. *(Conclusions #15, #17)*

Improvements and upgrades to the GCC staffing should include the following:

1. Qualify additional gas controllers, through additional hires and cross-training of other employees, to add to the current rotation and provide backup for emergencies and absences or departures by existing controllers.
2. Provide additional training beyond the on-the-job training currently provided, including use of a simulator.
3. Have a minimum of two qualified controllers in the GCC building at all times, even if only one is on active duty.
4. Qualify at least two controllers to act in a supervisory capacity over the GCC in the absence of the Supervisor.
5. Run periodic emergency drills on a simulator for existing controllers.
6. Change the reporting relationship so that the Supervisor of Gas Control reports to a manager or officer whose primary responsibilities are gas-related.
7. Consider the establishment of a "shift supervisor" position and/or role for emergency conditions and peak days.

Item #6 in the recommendation is addressed through the separate recommendation calling for the establishment of a gas business unit.

The elements of this recommendation should be considered in conjunction with the following recommendation to upgrade the GCC physical facilities.

2. Upgrade the Gas Control Center physical facilities. *(Conclusions #16, #17)*

Upgrades to the GCC should include the following:

1. Incorporate into the ongoing SCADA upgrade project a large interactive video board which would enable an overview of the entire system.
2. Redesign the GCC to incorporate the video board, allow better viewing of that board, to improve the physical security of the "wall of windows," and generally upgrade the warehouse look and feel of the GCC.

3. Incorporate a simulator for training purposes in the (recently relocated) backup control center[10] or another location.

Liberty considers the upgrades described above to be the minimum necessary to achieve a reasonable level of safety and reliability associated with potential emergency conditions.

Liberty understands that Iberdrola is considering relocating the GCC to a location adjacent to and accessible only through the Electric Control Center. There may be a FERC separation of functions issue associated with that location. It is essential that Gas Supply be in regular contact with gas control personnel and have the ability for physical access. The company should investigate carefully whether that potential location may be in conflict with FERC rules.

A related recommendation, included in Chapter VII, System Planning - Gas is to develop a long term system vision and plan which would include additional monitoring and control points on the gas system.

3. Perform a weather study to determine the proper design day and design winter HDD targets. *(Conclusion #3, #13, #14, #18)*

The Company should perform a design day and design winter study by operating area, using readily available weather data (e.g., NOAA), to determine the design day and design winter requirements for the various geographic areas it serves and for the entire system. The study should also include a calculation of the reserve margin required for balancing and potential variations in lieu of the general reserve margin.

The study is within the capabilities of several of the existing gas supply staff members, but the Gas Supply group is very thin now, even at its full staff complement. A new hire is needed to increase the level of resources, provide additional analytical capability, as well as additional bench depth for succession planning purposes. Once the study is complete and decisions are made and reviewed by PSC Staff, implementation would be accomplished in the normal course of business of Gas Supply asset review and contracting.

4. Improve the short-term (one-to-five day) forecasting process. *(Conclusion #3, #19)*

The short-term forecast is the basis for the daily gas purchasing, dispatch, and remarketing of assets not needed for that day and not already remarketed on a longer term basis (e.g., monthly capacity releases). Iberdrola's forecasting model is, like its other forecasting models addressed in Chapter IV, Load Forecasting, a basic, unsophisticated model which does the job without much precision and with a great deal of variance. For example, Iberdrola's model does not consider wind speed or day of the week,[11] which are known to be strongly correlated with HDDs and used in short-term forecasting by many LDCs.

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[10] In anticipation of impending flooding from Tropical Storm Irene, the backup control center was relocated from the basement of a NYSEG service facility close to the GCC to the Kirkwood building. The backup control center also flooded in 2005 at that basement location.
[11] Many large users are closed on weekends, which has a significant effect on load.

Short-term forecasting is an activity that every LDC is required to perform on a daily basis. The Company should investigate and purchase or develop a more sophisticated modeling process and should monitor and track its performance on a continuing basis.

As with the previous recommendation, it is within the capabilities of several of the existing staff members, but the limitations described above apply in this instance as well.

Budgeting

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X. Budgeting

Budgeting is an important central corporate process that establishes all spending plans and Board of Directors authorizations for the next calendar year. The IUSA capital expenditure budgets have increased significantly in the past few years, which is one of the key reasons for the need for rate increases in accordance with the rate plans established for 2011-2013.

NYSEG and RG&E have systems and processes in place to affect the development of annual budgets that identify system requirements from the bottom-up. The Companies also have used top-down expenditure targeting in recent years to provide spending targets and resulting financial discipline for the budgeting process.

The budgeting process has been stressed by capital spending requirements of the Iberdrola merger Order, as well as the increased spending levels set by the three-year rate plan. The rate plan leads and defines the spending levels of the annual budgets, which should be designed to provide direct linkage to and defined progress toward meeting the rate plan and longer-term plans. IUSA should also use long-term economic and reliability methods to justify projects and allow the consistent allocation of funds among organizations and projects.

A. Background

The development of the NYSEG and RG&E annual budgets involves a broad spectrum of the Company management. The budget establishes all capital and operating expense spending planned for the budget year. The process starts with executive management targeting of financial goals and objectives. It includes the building of the budget from the bottom-up by field managers and engineers. The process provides for the identification, analysis, and justification of projects and expenditures by each functional organization. After the development of budget proposals, middle management reviews, adjusts, and eventually approves a proposed budget for each major organization. Review and approval processes continue at executive management levels, including any allocation or reallocation of spending among the various organizations. The budget is then presented to the IUSA Board of Directors for approval. Chapter 2 of this report addresses the role of the IUSA board in detail, and therefore provides additional context for understanding the issues raised in this chapter.

Liberty has reviewed and evaluated the IUSA budgeting process for NYSEG and RG&E from initiation to completion, focusing on the 2010 and 2011 budget years. Liberty's evaluation has focused on three broad categories. Those categories and the evaluation criteria that govern each are:

- Budget targets and planning
    - Senior management and the IUSA Board of Directors should take reasonable efforts to assure that NYSEG and RG&E needs receive sufficient priorities for spending at the parent level.
    - The IUSA Board should take direct responsibility for budget approval, and should support their responsibility to do so by securing from management information about expenditures, operations performance, and the relationship between the two.

  - Budget values, goals, and objectives should be consistent with good utility practice and with the expectations of the Commission with respect to promoting service adequacy, while considering efficiency and economy in the long run.
  - The capital budget should be derived primarily from a bottom-up examination of system needs; it should not be unduly driven by top-down financial considerations.

- Budget process and prioritization
  - The detailed budgeting process should involve all of the organizations whose distinct contributions to utility service require material capital expenditures.
  - The budgeting process should take place under guidelines, procedures, and schedules that produce results that are sufficiently uniform to combine into a consolidated, overall budget.
  - Budgets approved should be structured to allow for meaningful measurement, approval, and control of increases that may prove to be required as projects progress.
  - Budget categories and details should as nearly as possible conform to cost management and measurement bases.
  - Items of expenditure (at both the project level and the categorical level) should undergo modeling under consistent methods and with similar tools, which should produce a sound basis for objectively estimating and comparing their initial and total-life costs, and for allowing a comparison of the costs of alternatives for meeting identified needs.
  - There should be comprehensive, documented cost analysis and budgeting procedures, and there should be sufficient reviews of modeling and budgeting results to allow for continuous methods and tools improvements.
  - Economic analysis should comprise an essential tool of capital requirements planning and should comprehensively capture annual and total-life O&M costs of economically-driven capital additions.
  - There should be a clear and timely process for expenditure prioritization with as much objectivity as can be incorporated into that process.
  - There should be periodic, structured examinations of the ultimate effectiveness and economy of past prioritization efforts (i.e., projects that did and did not “make the cut”), in order to validate the effectiveness of prioritization processes and decisions.

- Management reporting
  - Budget variances should be identified, evaluated, and corrective action taken as needed for effective management of the process.
  - Significant increases or decreases to the capital budget should be properly justified and approved by senior management and the Board.
  - Other financial constraints should not operate as a barrier to capital expenditures; sound analysis of financial alternatives and consequences should support the adoption of any financially-driven budget constraints.
  - Budgeting should not consider rate case proposed expenditures to act as a cap on expenditure levels.
  - Budgets developed and used for internal purposes should be consistent with those incorporated into revenue-requirements analyses used and presented for regulatory purposes.

- Audited feedback loops should be in place and operated effectively so that both the management of the budget and the quality of the financial information on which decisions are made constantly improve.

B. Findings

1. Budget Targets and Planning

IUSA begins its annual budget process by setting high-level financial targets that provide business units and managers with allowed spending levels for the development of projects, programs and operating expenditures. IUSA budget "targets" are determined by starting with the capital expenditures and operating expenses approved in each business segment's three-year rate plan. IUSA staff models the capital spending levels from the rate plans and includes a 10 percent return on equity as a minimum target, and up to 11 percent. They also strive to improve the credit rating metrics by growing cash flow by 2 to 4 percent per year with improving short-term liquidity through the forecasts.

The IUSA Administration and Control group serves as the coordinator and overseer of the budget process. They are assisted by the NYSEG/RG&E Controller's group. IUSA Control sends out budget guidelines to all budget-responsible entities around August 1 to kick off the process. The package includes budget schedules, deliverables required, and the information required to load budget information into SAP for an October finish date. Approximately 15 budget contacts help develop the budget for the "five utility business units." The budget guidelines act as instructions to the functional areas. Each functional area has one control person who coordinates the budget input. The budget guidelines include consistent corporate assumptions, such as headcount and inflation factors for everyone to use.

IUSA emphasizes that the budget guidelines memo and schedule is based on the rate plans for the New York Companies. The actual guidance includes the rate plans and any new information such as additional work force reductions, litigation, capital expenditure levels, financings, and environmental spending. After the functional areas provide their proposed bottom-up operating expenses, IUSA Control looks at a first cut of the budget versus the rate plans for capital expenditures and operating expenses. The Companies advise that some flexibility is allowed and that the budgets and rate plans don't have to match; the issue is whether the bottom-up proposals and the rate plan are grossly different.

IUSA does not have targets or goals for the variance from budget on a total, annual basis for capital expenditures or O&M, for either business units or by company. On a monthly basis, variances for projects or for specific line items are identified that are 10 percent or more above or below the budgeted amount, and explanations and mediation plans are required of the responsible managers.

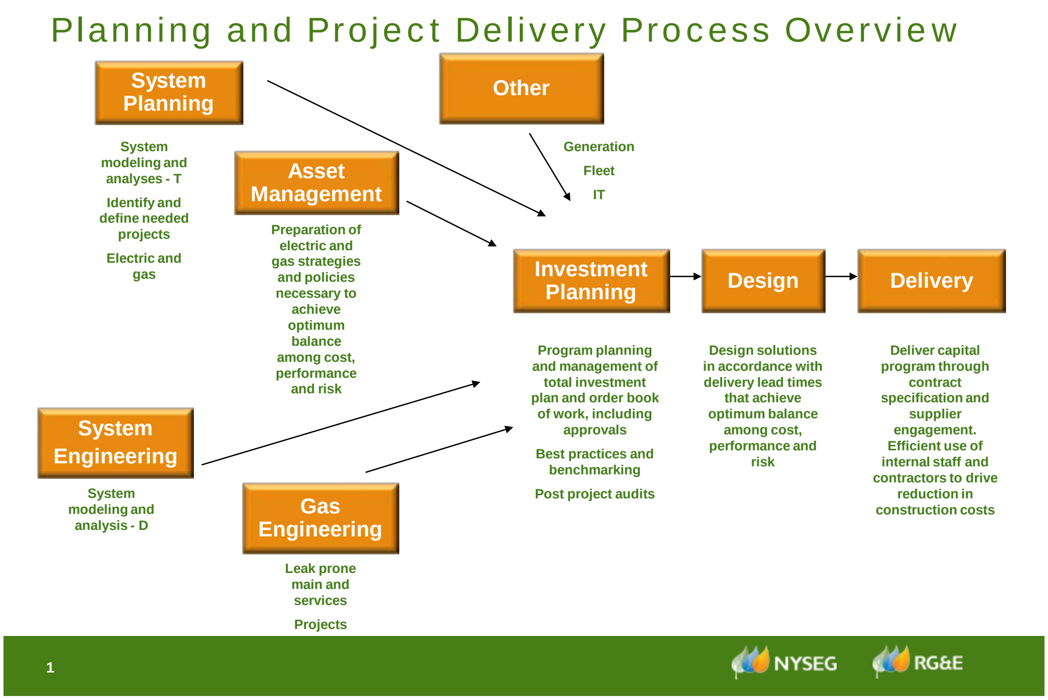
2. The Capital Budget

a. Process Overview

This section of the report reviews how IUSA identifies, analyzes, prioritizes, and presents the capital budget for approval by executive management and the Boards of Directors. The effectiveness with which IUSA selects the most advantageous capital expenditures for the New York Companies is an important determinant of its ability to build required utility facilities and infrastructure at the most reasonable cost possible over the long term.

IUSA and the New York Companies have extensively changed the organizations and some of the processes that perform capital budgeting. For instance, the Asset Management and Investment Planning groups were established within the engineering group to provide more review and emphasis on infrastructure and to better coordinate capital spending, respectively. New capital project reports have been established in 2011. They provide excellent information and graphic tracking of the capital plan against actual results. The capital budgeting processes have also been merged for NYSEG, RG&E and CMP. A difficult challenge relating to this combination is the different engineering standards in place across the three utilities. IUSA engineering is trying to establish common standards through a special business transformation project. The project has five sub-teams: transmission, distribution, substation, meters and protection. Each team had a goal for 2011 of working on 25 of the most important standards; management believes it as at least a three-to-five year project.

The chart below graphically depicts the process flow for capital budgeting, as currently organized.



In the rate case process, specific capital expenditure proposals are presented and approved. “Appendix L” of the rate order details the capital expenditures included in rates. IUSA provides a targeted range of capital expenditures for the three utility Companies in total for the budget.

The bottom-up capital budgeting process starts with system planning. This group uses a ten-year system planning model that identifies transmission, substation, and other large project requirements. System Planning analyzes the current system against load forecasts, generation dispatch scenarios, and contingency conditions, and evaluates system performance against system planning criteria. System needs are identified, and system engineering (design) proposes solutions to resolve identified deficiencies. System planning's analyses do not consider asset health and condition, but assume that all assets are capable of operating at their full design ratings.

A second area of emphasis is maintenance projects and programs. For instance, transformers that need to be replaced are identified. The TDIRP (T&D Infrastructure and Reliability Program) program is an electric upgrade program; generally these programs look one year ahead at reliability needs. The electric reliability committee also proposes projects.

Maintenance delivery oversees the maintenance, testing, and inspection programs for all assets in service. Based on the results of these programs, maintenance delivery recommends alternative maintenance or inspection intervals, repair, rebuilding, or replacement of assets. These projects are prioritized and the capital projects are proposed to Investment Planning for incorporation into the capital plan and schedule.

The recently-established asset management effort employs a health index for major system infrastructure. This effort is being upgraded to become a more data-driven evaluation of existing assets and their condition. Asset management assesses the criticality of potential asset losses, and also attempts to balance capital spending versus maintenance. Asset management may produce asset replacement recommendations based upon the health index (condition) and risk assessments (risk of failure on reliability, safety, environments, etc.) of assets. Capital project inputs are expected from this group in the future.

Investment planning also receives capital expenditure information regarding capital project carryovers from electric capital delivery on budgeted projects not completed during the budget year. A central services organization provides capital expenditure requests for facilities, fleet, and general service. The gas operations capital is provided separately by gas operations/engineering. Capital projects and programs are also proposed by T&D operations and generation. Investment planning reports that these groups were asked to prioritize their 2012 budget projects in three levels. Priority one is high priority that should be completed within the next year. Priority two is of medium concern, with recommended start dates in one to two years. Priority three is lower, involving work required after two years. Investment planning noted that all capital budget requesters did not provide prioritizations on a bottom-up basis for the 2012 budget.

Investment planning then prioritizes and combines those projects into the proposed capital budget. High priority project needs, including regulatory required or government required (including compliance with NERC and Department of Transportation requirements) will be funded first in the investment planning process. Additional projects will be prioritized and funded based on system reliability needs and risks. The heads of each budgeting organization will discuss and negotiate a budget with the asset management/investment planning group, who may suggest deferrals. In the third quarter, iterations to the capital budget are performed.

A prioritized capital budget is then presented to the IUSA VP of engineering. Once the VP of engineering's authorization is obtained, the budget is presented to the IUSA CFO, who in turn makes a presentation to the senior management team. With the approval of the senior management team, the budget is presented by the New York President to the IUSA Board of Directors for approval.

Following approval, the investment planning organization is responsible for capital for all of IUSA, and IUSA administration and control is responsible for O&M for all Companies.

Projects in the approved work plan are managed by the capital delivery group until they are commissioned as in-service assets. The capital delivery project manager for a project convenes the project team and develops a project schedule. System engineering prepares a detailed scope and bill of materials from the project scope, which further develops the schedule and budget. The project manager continues to monitor the schedule and budget through construction and commissioning.

b. Project Initiation – Electric System Planning

The NYSEG/RG&E system planning department prepares ten-year reliability assessments that are updated biennially. The purpose of the ten-year studies is to identify the long-range system problems due to forced or maintenance outages that may occur on the NYSEG and RG&E transmission and sub-transmission systems over the next ten years, and to recommend system reinforcements that would be required to correct these system problems. A key input to the studies is a load forecast that is a regression analysis based on recent load history.

The ten-year model analysis prepares a set of results for 14 different load areas for NYSEG and RG&E. The required reinforcement projects are identified in each reliability run set. Once the recommended system reinforcements been identified, system planning then utilizes three separate metrics to compare and prioritize these recommended projects. The key criteria for project identification and prioritization are megawatts of load lost, number of customers affected and hours of loss exposure.

Cost estimates for the projects are prepared by system engineering. A "first estimate" set of estimates is included in the three-year rate plan and in the new five-year capital plans. For the capital budget process, identified capital investments may have more detailed specifications and cost estimates. However, refined estimates take place later in the project process. According to company management, the capital budget has historically been a rolling two-year budget with detailed estimates for the first year. A detailed five-year capital plan was completed in April, 2011 and submitted to the NYPSC. Asset management and investment planning are provided the information on the projects, dollar estimates, and priorities for near-term projects.

Some situations are identified that cannot be adequately served during certain forced or maintenance contingencies. In such situations, other selected areas of impact are evaluated and available resources are allocated in a manner that will maximize the benefit. The variables evaluated in addition to the system planning metrics can include the probability of the event occurring and its associated risk, the frequency and duration of the outage, the number and criticality of customers impacted, lost revenue, damage claims, and the cost of system upgrades.

c. Maintenance and Asset Management Capital

i. Maintenance Programs

A second area of emphasis in initiating capital expenditures comprises maintenance projects and programs. For instance, transformers are identified that need to be replaced. The TDIRP program is in place to enhance reliability. Based on the results of these programs, maintenance delivery recommends maintenance or inspection intervals and the repair, rebuilding, or replacement of assets. These projects are prioritized and the capital projects are proposed to Investment Planning for incorporation into the capital plan and schedule.

Maintenance capital programs or projects are identified by maintenance delivery in three primary categories: maintenance programs, testing programs, and inspection programs. For maintenance programs, the Companies establish programs as needed to maintain system reliability. The most important issue is vegetation management, which causes 30 percent of outages. Another maintenance program is the visual inspection of 20 percent of the poles each year. Helicopter inspections of transmission lines are also on a regular program. Most of the maintenance work identified is classified as maintenance expense and not capitalized.

Testing programs include the testing of relays, the annual testing of breakers and stray voltage testing. Maintenance delivery sets up the testing regimens. However, field employees actually do the inspections. Maintenance delivery "owns" the program, but not the maintenance fix.

A third important area is the inspection programs. This program includes actual inspections and the follow-up that is required. Inspection programs grade assets in three categories: level I requires action immediately; level II is needed in the next six months; and level III is needed after six months. While maintenance delivery and engineering identifies deficiencies, the local division offices are responsible for fixing the deficiency. The regional division budgets for the capital or the O&M required to fix the problems identified. Maintenance delivery also makes recommendations that include O&M programs, except when interruptions are experienced and they can identify certain equipment vintages as root causes. To replace troubled vintages, maintenance delivery will propose a capital replacement program.

Some of the maintenance fixes that are identified are capital expenditures. This includes TDIRP projects such as sectionalizing lines, establishing redundancy in transformers, replacing switchgear, and substation network equipment. Maintenance delivery may identify these types of projects, and the engineering group estimates and prioritizes the project in the capital budget. The regional divisions budget for division minors, which are routine capital expenditure programs.

ii. Asset Management

The asset management effort is relatively new at IUSA and the New York Companies. Asset management utilizes a health index to evaluate major system infrastructure. The criticality of potential asset losses is assessed, and asset management also attempts to balance capital spending versus maintenance. Asset management may produce asset replacement recommendations based upon the condition and risk assessments of assets.

IUSA asset management follows a UK idea and framework, specifically from Scottish Power. The new asset management group is developing asset management policies based on PAS 55 (Publicly Available Standard Number 55). The general asset management process is to first perform a condition assessment, and then a risk assessment. The combination of this data yields a health index with a value of 1 to 5, with 1 being best. The asset management objective is to optimize asset values over their lives.

The new asset management group has a manager and six employees (four engineers and two analysts) who will be analyzing about 100 asset categories over the next several years. The group is analyzing assets and data across IUSA, and is performing evaluations for transmission, substation and distribution for both gas and electric. They are concerned only with the T&D and natural gas delivery networks, and will not review facilities or hydro assets. A key function is to assess the end-of-life for all major asset classes. They perform a grading of assets, and provide recommendations to repair or replace.

The first major asset management report was dated July 2011. Three asset categories were completed: substation breakers, substation batteries, and distribution poles. The asset management risk assessments include a category one that should be placed in the budget “in the next five years.” The category two classification includes assets that require “no firm plans” for including in the capital budget. In the completed report, the asset management team found that age was the best criteria in predicting distribution pole condition, and that after 50 years, the failure rate increases greatly. NYSEG, for instance, has 17 percent of their poles that are more than 60 years old. Since there are about 100 categories of assets, the project will be very long-term. The health index approach is significantly different from a system planning reliability approach that is based on overloads. The asset management approach is based on asset condition. Conditions may be evaluated visually, by oil samples, by measuring loads or by age.

The information gained thus far was used in the 2012 budget for capital expenditures. However, only a few related additions to the capital budget were made for 2012. For instance, some substation breakers were included in the budget. The next groups of assets to be evaluated will be substation power transformers, underground cables and medium voltage pad-mounted switchgear. In the future, greater dollar amounts will be invested in TDIRP and division minors due to asset management.

d. Electric Design and Estimating

Project designs, specifications and cost estimates are jointly developed by electric system engineering and the new project management organization. Company managers note that the project management organization has been recently brought into the capital budgeting process early to promote project ownership. Three organizations are now heavily involved in this process: system planning, system engineering and project management.

Capital expenditure project initiation for the electric network is primarily driven by system planning for new projects and asset management, electric maintenance delivery and gas design and delivery for existing assets. Maintenance delivery performs inspections and vegetation maintenance.

System engineering includes three primary groups and functions. Project cost estimating performs project scoping, line design and cost estimates; they provide the first planning estimate for all system planning projects. The design group sets standards and material specifications and new technologies. The goal of the design group for 2011 is to set 25 new standards in each of five areas that are consistent among the three Utilities. The capital support group provides project engineering for capital expenditure projects.

Project estimating generally has three levels. The first level is a ballpark planning estimate. A second-level estimate is for executive and Board approval and is more refined. The third level is the final estimate that includes the last 30 percent of the design work. This is the estimate used after a project has been approved and is going out to bid. Each of the engineering areas has their own estimating "tool." For instance, transmission engineering has an estimating spreadsheet tool. Distribution engineering uses an SAP work management application to estimate job build-out. Substation engineering has a third estimating tool that is a spreadsheet focused on system protection.

The first level or planning estimate is a generic equipment estimate that uses large, coarse building blocks. The planning estimate is not meant to be specific or precise. For three-year forecasted rate plans, regulatory would be working from first planning estimates, as more refined estimates probably have not been made. However, the Company generally manages to the rate plan, and discusses with the NYPSC changes to "Appendix L" approved projects.

A two-year rolling capital expenditure budget has been the traditional format for the New York Companies. System engineering notes that the first capital budget year included "second" estimates, while the second year included planning estimates. For longer-term planning, the system planning model provided needed capital additions from 2 to 10 years; these years included first-cut engineering estimates. More recently, IUSA filed detailed five-year capital plan with the NYPSC in April 2011.

e. Gas Operations

Gas Planning is responsible for development of the gas operations capital budget, including all replacements and infrastructure improvements. Gas planning coordinates recommendations and requests for capital projects from gas engineering and design, corrosion engineering, and gas field operations. Company managers first look at the rate case "Appendix L" projects and programs for gas projects; this forms the base of the capital budget. Secondly, leak history and corrosion undergo evaluation to form a "leak prone section" of the budget for replacements. Replacements of leak prone mains are proposed by the corrosion engineering group for system improvements and replacement of low pressure mains with medium pressure mains. The recommendations received from the corrosion engineering group are based on a risk prioritization process.

The gas system planning Stoner model is utilized to identify low pressures and new load impacts and where reinforcements and replacements are required. Highway projects initiated in the budget year tend to be a big variable in gas capital expenditures. New growth and main extensions are analyzed with an economically-driven surcharge calculation sheet. Gas planning works with gas design to develop budget level cost estimates for various system improvements. A first estimate is performed on budget projects; this estimate is expected to be very rough, and + or – 40% is expected.

The order in Case 09-G-0716 requires NYSEG to replace a minimum of 24 miles of leak-prone gas main annually. This includes leak-prone main replaced in conjunction with municipal projects and leak-prone main replaced as prioritized based on leaks, corrosion and risk. Leak-prone services associated with the mains are also replaced, contributing to the annual requirement to replace 1,200 leak-prone services. The rate order in RG&E's parallel case also requires replacement of a minimum of 24 miles of leak-prone gas main annually. Leak-prone services associated with the mains are also replaced, contributing to the annual requirement to replace 1,000 leak-prone services.

Leak-prone mains that are either cast iron or bare steel are identified and prioritized based on risk based methods, which use leak history. Low-pressure main replacements are grouped into projects that will eliminate low-pressure points and replace low-pressure regulator stations with medium pressure facilities.

Criteria for gas regulator station replacements and upgrades are based on station condition, performance, and existing design, as compared to current standards. High priority is given to stations with obsolete equipment, where repair parts are not available.

Transmission mains are also evaluated and considered for replacement based on Integrity Management Program (IMP) inspection findings and age. Priority is given to transmission mains installed prior to 1960. In addition, NYSEG and RG&E are currently developing a new process to prioritize gas transmission related projects based on risk based criteria and a casing evaluation process.

Gas operations does not currently prioritize capital projects from the bottom-up. However, they are now working on a gas planning manual that will include prioritization criteria. The prioritization criteria will include leak history, type of pipe, coatings, old-vintage plastic, and regulator capacity.

f. Other Capital Expenditures

The 2011 budget for New York electric operations included capital expenditures for T&D operations of about $116 million. However, the central engineering organization described previously budgets for almost all of the capital items, and also prepares some of the routine capital expenditure programs. T&D operations budgets for a minority of its routine capital expenditure programs. Estimates for these limited routine items are made by using the three-year historical trend and adjusting for known changes.

The fossil/hydro organization is responsible for its own capital budget, which includes primarily maintenance expenditures. Fossil/hydro also has a few major capital items, such as the Hydro Station five tunnel repair over the next three or four years. The fossil/hydro manager performs a prioritization on the projects that go into the bottom-up capital budget. The priorities are: a) safety, including hydro-dam regulatory requirements; b) FERC licensing requirements; c) hydro-dam repairs required to maintain operations; and d) efficiency projects that are of a more discretionary nature.

The IT organizations also budget their own capital expenditures, which include computer hardware, software and capitalized labor. Software is an operating expense, and is only capitalized if it is $500,000 or more for the New York Companies. Leases include IBM mainframe leases, as well as a PC computer lease for four years with Dell.

Capital expenditures are prioritized by entering New York IT projects into a parallel Iberdrola SA IT system called Clarity. This system is specific to the Iberdrola IT system for all companies worldwide. Iberdrola SA will prioritize and approve IT capital expenditures within the central Spanish IT group. According to the Company, this centralized process eliminates redundancies in IT investments.

g. Historical Capital Budget Results

The capital budget tables for NYSEG and RG&E below provide comparisons of the "Plan" approved by executive management and the Board of Directors prior to the start of the budget year versus actual expenses experienced for the years 2006-2010.

NYSEG Capital Expenditures Plan vs. Actual

	2006		2007		2008		2009		2010	
Category	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan
Electric Department:										
Transmission Lines	4,944	7,257	6,530	8,137	14,102	12,448	26,491	28,330	51,685	34,296
Distribution Lines	16,610	11,227	13,629	14,869	16,493	14,615	14,814	19,382	40,404	11,931
Customer - Industrial Commercial	903	2,726	739	832	2,195	793	1,299	-	771	855
Government Highway / Road Jobs	1,425	1,988	2,031	4,061	2,480	3,782	1,574	3,833	1,651	1,698
Residential Line Extensions	4,362	7,723	4,211	5,558	3,859	4,883	3,430	1,946	2,541	3,592
Service Connects	3,554	2,656	2,254	3,006	1,826	2,592	2,300	2,080	4,688	1,426
Street Lighting	1,016	864	1,013	640	1,189	639	1,217	832	857	930
Storm Restoration	2,623	400	(94)	1,153	796	722	1,797	640	1,442	868
Substations	21,801	20,968	13,696	16,016	27,011	37,174	21,150	75,773	31,923	52,470
Distribution Line Transformers	11,516	9,000	13,072	10,000	13,911	12,032	13,940	14,152	19,150	14,831
Electric Regulators and Reclosers	1,608	-	1,578	1,120	1,698	1,120	1,065	224	1,973	992
Electric Meters	1,983	3,300	2,040	2,400	2,037	2,800	3,369	2,200	1,943	3,500
Miscellaneous Electric	10	-	62	-	67	(2,961)	63	0	74	-
Total Electric	72,355	68,109	60,762	67,792	87,665	90,639	92,508	149,392	159,102	127,389
Electric Variance Percentage	6.23%		-10.37%		-3.28%		-38.08%		24.89%	
Gas Department:										
Distribution Mains - New Business	1,573	1,333	2,106	1,945	4,937	2,169	1,487	1,222	690	1,375
Distribution Mains - Replacement / Reliability	1,763	2,516	1,833	2,553	2,691	2,977	4,337	6,036	4,849	5,331
Production Plant	-	-	-	-	264	-	98	-	-	-
Transmission Mains	(31)	-	5	60	25	-	80	-	179	-
Services	7,446	5,150	7,009	6,718	10,936	7,404	9,695	7,454	9,080	7,687
Government Jobs	2,516	1,984	2,901	2,572	3,445	2,892	3,292	2,322	3,233	3,811
M&R / Gate Stations	874	1,737	2,349	1,960	1,033	1,661	787	714	156	-
Gas Meters	1,049	1,400	1,578	1,440	3,362	3,726	3,503	3,796	4,180	3,796
Regulators, Instruments, Other	182	-	128	169	134	1,549	109	1,911	291	-
Total Gas	15,372	14,120	17,909	17,417	26,827	22,378	23,388	23,455	22,657	22,000
Gas Variance Percentage	8.87%		2.83%		19.88%		-0.29%		2.98%	
Generation:										
Production - Hydro	1,960	2,433	1,710	2,700	1,653	3,187	1,423	4,420	2,541	2,100
Total Generation	1,960	2,433	1,710	2,700	1,653	3,187	1,423	4,420	2,541	2,100
Generation Variance Percentage	-19.45%		-36.66%		-48.14%		-67.80%		20.99%	
General Department:										
General Land & Structures	1,656	1,838	7,514	2,100	6,559	1,852	1,858	2,040	14,539	3,940
Major Projects	1,406	-	(549)	2,141	(6)	-	339	0	(26)	-
General Equipment	8,308	22,545	15,666	29,835	21,942	82,368	1,502	11,140	11,160	10,014
Transportation Equipment	13,127	16,600	15,101	17,462	12,573	18,386	3,489	19,500	20,542	6,000
Software	10,865	14,500	-	-	-	-		-	-	-
Other	17,145	955	-	-	-	-	-	3,835	-	-
Total General	52,507	56,438	37,732	51,538	41,068	102,606	7,189	36,515	46,214	19,954
General Variance Percentage	-6.96%		-26.79%		-59.98%		-80.31%		131.60%	
Capital Total	142,194	141,100	118,113	139,447	157,213	218,810	124,508	213,782	230,514	171,443
Capital Total Variance Percentage	0.78%		-15.30%		-28.15%		-41.76%		34.46%	

RG&E Capital Expenditures Plan vs. Actual

	2006		2007		2008		2009		2010	
Category	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan
Electric Department:										
Transmission Lines	36,990	95,069	34,726	70,451	11,388	22,640	1,990	15,471	10,108	5,442
Distribution Lines	6,505	6,656	7,534	8,775	12,379	8,010	7,017	10,789	17,268	2,875
Customer - Industrial Commercial	1,460	1,200	667	1,318	1,121	1,240	1,652	-	715	1,009
Government Highway / Road Jobs	3,500	4,573	3,487	5,843	2,373	8,087	4,710	7,917	7,189	9,415
Residential Line Extensions	1,411	1,298	1,227	1,694	1,374	1,865	1,081	-	859	1,896
Service Connects	491	800	477	930	650	776	845	735	686	616
Street Lighting	936	601	53	681	430	746	678	720	(6,483)	560
Storm Restoration	331	-	342	466	383	465	172	405	127	365
Substations	28,684	5,003	51,893	21,600	32,147	56,930	20,213	58,647	24,584	35,680
Distribution Line Transformers	2,986	1,700	3,131	2,777	3,930	3,378	4,952	3,540	5,130	4,528
Electric Regulators and Reclosers	194	130	26	465	218	46	55	0	284	84
Electric Meters	788	1,000	1,015	1,000	867	1,200	972	1,200	991	1,000
Miscellaneous Electric	469	568	(82)	-	12	-	(42)	0	16	1,915
Total Electric	84,744	118,598	104,495	116,000	67,274	105,383	44,295	99,424	61,473	65,385
Electric Variance Percentage	-28.55%		-9.92%		-36.16%		-55.45%		-5.98%	
Gas Department:										
Transmission Mains	-	-	-	-	297	410	5	-	675	-
Distribution Mains - New Businesss	1,726	2,936	1,470	2,450	3,946	3,740	902	1,272	736	1,300
Distribution Mains - Replacement / Reliability	4,750	7,915	5,889	6,691	4,830	5,960	4,146	7,914	5,292	7,218
Services	5,782	6,180	5,386	4,469	6,245	5,600	6,084	7,145	7,262	7,141
Government Jobs	2,612	3,194	2,655	3,038	2,354	3,384	3,738	4,924	3,481	3,563
M&R / Gate Stations	718	300	444	680	1,321	680	143	1,720	964	-
Gas Meters	1,329	1,200	1,985	1,712	2,543	2,562	2,524	2,655	3,253	2,655
Regulators, Instruments, Other	73	275	362	160	193	(49)	124	352	314	123
Total Gas	16,989	22,000	18,190	19,200	21,729	22,287	17,665	25,982	21,977	22,000
Gas Variance Percentage	-22.78%		-5.26%		-2.50%		-32.01%		-0.10%	
Generation:										
Production - Fossil	1,711	1,584	758	49	5,079	15,844	(290)	-	17,310	11,325
Production - Hydro	2,345	2,937	7,916	12,551	34,993	36,489	(189)	25,731	(2)	25
Total Generation	4,056	4,521	8,674	12,600	40,072	52,333	(479)	25,731	17,308	11,350
Generation Variance Percentage	-10.28%		-31.16%		-23.43%		-101.86%		52.50%	
General Department:										
General Land & Structures	1,976	1,347	2,836	996	3,065	1,915	961	1,500	1,927	1,400
General Equipment	1,118	603	4,516	4,957	6,176	20,330	693	1,936	4,660	3,318
Transportation Equipment	3,248	3,800	4,680	5,561	4,766	6,186	818	4,400	4,851	1,566
Software	29,235	31,213								
Other	1,011	199	-	-	-	-	-	1,719	-	-
Total General	36,589	37,162	12,032	11,514	14,008	28,431	2,472	9,555	11,438	6,284
General Variance Percentage	-1.54%		4.50%		-50.73%		-101.86%		82.02%	
Capital Total	142,379	182,281	143,390	159,314	143,083	208,434	63,953	160,692	112,196	105,019
Capital Total Variance Percentage	-21.89%		-10.00%		-31.35%		-60.20%		6.83%	

3. O&M Budgeting

a. O&M Budget Processes Overview

The O&M budget process is initiated by the budget guidelines memo that is sent to key budget-responsible contacts in several departments in mid-to-late July. The budget guidelines are developed by IUSA Administration & Control, and include step-by-step schedules and deadlines. The memo includes a schedule for each piece of the budget. The process starts with sales forecasts and margins, which are provided by the IUSA regulatory group. Energy supply information is provided by energy supply for NYSEG and RG&E.

The following are key contacts that provide information for the O&M budget:

IUSA Tax Department – Property taxes, Income tax rates and adjustments
IUSA Treasury – Long- and short-term interest, financings

O&M contacts:
NY T&D Operations
NY Customer Service
Engineering
Public Affairs
Gas Operations
Regulatory
General Services (Materials, supplies, purchasing)
Information Technology (IT)
NY President's office
Human Resources/Environmental
Headcount, benefits, payroll
Fossil/Hydro
Energy Supply

Following the receipt of the budget guidelines in each budget-responsible organization, budgets are developed from the bottom-up. The regulatory department has responsibility for revenue forecasting, in conjunction with energy supply. Budget coordinators in electric operations, engineering, gas operations, general services, IT, finance, regulatory, human resources, fossil/hydro, energy supply, public affairs, and customer service each develop "departmental budgets" from the bottom-up. While specific O&M budget spending limitations are not expressly communicated, employees understand that departmental O&M budgets should be limited to the amount included in the last rate Order.

Operating and engineering managers and Vice Presidents review and approve their departmental budgets, which are coordinated for each functional area and submitted to the New York Controller's office for review. The budget "control team" reviews the first cut of bottom-up operating expenses versus the rate plan for both capital expenditures and operating expenses. The control team then asks basic questions of the functional managers and makes adjustments to the budgets until an agreement is reached. The budgets for each area are then reviewed and approved by the New York Controller and the New York COO and President.

The next authorization level is IUMC administration & control and the CFO at IUSA Finance, who review and approve the budget. The IUSA CFO then makes a presentation to the IUSA senior management team. With the approval of the senior management team, the budget is presented to the IUSA, NYSEG and RG&E Boards of Directors for approval.

b. Departmental O&M Budgeting

O&M budgets arise from bottom-up processes within each operating unit. Budget processes differ among the various units, because each has developed a process specific to its own operating functions. The following areas are the largest operations and are most labor-intensive, generating most of the O&M expenses.

- T&D operations

- Engineering
- Gas operations
- Customer operations
- General services.

Each organization has its own process in place to meet the major work objectives of its functional responsibilities. This section summarizes processes for developing operating expenses in each area. The capital budget process (the subject of the previous section of this chapter) runs on a parallel path.

i. T&D Operations

T&D operations assembles operating expenses by numerous cost centers that represent the field operations of NYSEG and RG&E. The most important elements of T&D operating expenses are labor and benefits, fleet expenses, maintenance expenses and operating expenses related to capital. Labor dollars for T&D operations are provided by the human resources department at IUSA. The vice president provides input regarding expected staff changes for the budget year.

The budget coordinator works with the budget-responsible managers to estimate operating expenses. Estimates are made for dollars per employee for total maintenance expense, capital dollars, storm expenses, etc. using historical trends for the Companies. The budget coordinator also estimates external service costs such as contractors and dig safety locators, which are key T&D expenses. Estimates are made for materials expense and safety expense through expense pools. Operating expenses are budgeted by individual business units, and also as a whole.

The budget coordinator prepares the bottom-up budget in August and September and submits it to IUMC planning. The budget is negotiated with the planning and control groups in October. At the end of January, budget Revision 1 is performed, taking into account all changes since the time the budget was finalized and with one month of actual information. In May, Revision 2 is performed with actual information through April. Revision 3 is performed with six months of actual information. T&D operations is asked to revise their budget estimates for the remaining months of the budget year for each revision cycle.

ii. Engineering O&M Budgeting

The engineering area includes seven directors and 21 total managers and directors who are "budget responsible." Some of the managers are in charge of specific cost centers, whose services and budgets are allocated among the utility operating companies. The primary items in the operating expense budgets are payroll, outside contractors, employee expenses, IT expenses and office supplies. Human resources provide the engineering staffing costs that form the foundation for the budget.

The budget-responsible engineering directors and managers put together their individual budgets from the bottom-up and submit to the budget coordinator. The managers and directors are aware of a "bottom line" of allowed expenses that they receive from the vice president. The managers also use their historical expense levels to formulate their budget line items. Each of the directors and managers present their budget to the vice president, who provides feedback and required changes. Following approval from the vice president, the budgets are input into the SAP system, using templates provided by the New York controller's group.

iii. Gas Operations

Gas operations includes 25 field offices for NYSEG and 5 for RG&E. The field employees begin the budget process by reviewing 160 work tasks in 13 major categories to generate operating expense dollars. The field employees determine the manpower requirements for each activity, including labor and overtime. HR provides labor and benefits information for the 325 gas operations employees. O&M budgeting is activity-based in gas operations.

Budgeting for gas operations is effectively built around three "business activities": emergency response, mandated operating expenses and the capital expenditure budget. Hours for each of these activities, by office, are estimated, which provides a basis for the budget.

A large portion of the gas operating expense work is to comply with programs mandated by the NYPSC. The rate case plan includes targets for emergency response time, leaks, replacement of bare steel and cast iron, and inspections. The inspections that are required include leak surveys, valve and regulator inspection, corrosion surveys, and system meter replacements. Each of these programs has mandated inspection cycles from the NYPSC. Such programs and projects are included in the Companies' "Gas Operating Procedures."

iv. Customer Operations

The customer operations organization includes nine managers and directors. Separate call center managers oversee the Rochester and Binghamton call centers. Two field center managers have responsibility for meter reading, credit and collections, and shutoffs. Other managers oversee quality and budgeting, billing and collections, sundry billing and collections, and the energy efficiency group. IUSA outsources the billing function, which relies upon information collected by the SAP system. IUSA also outsources remittance processing and meter reading. Operating expenses comprise the bulk of the customer service budget, with payroll-related expenses the largest contributor. IUSA also incurs significant expenses for external contractors in the areas outsourced.

Customer service builds bottom-up operating expense budgets from the last revision of the previous year's budget. They adjust for changes expected in the coming budget year. The monthly spread of expenses has remained fairly constant; payroll and contractors account for the majority of costs. Uncollectible accounts are budgeted by month. Each manager reviews and adjusts for expected changes a current management report from HR.

Each manager completes a full operating budget, and sends it to the budget coordinator. A project manager assigned to special projects budgets the related capital expenditures. The budget coordinator reviews the budgets, focusing on their year-to-year consistency.

There is not a process for prioritizing operating expenses for purposes of budgeting. The budget coordinator reports that all operating expenses are a priority.

v. Fossil/Hydro

For fossil/hydro, the budget process starts in September, when the budget coordinator receives a pre-loaded SAP template from New York planning and control. The template includes payroll and related items. Fossil/hydro will have a budget kickoff meeting and some weekly meetings thereafter. They discuss issues and problems such as maintenance projects and identify new costs from previous year's budgets. The budget coordinator estimates expenditures required for regulatory mandates, or for regulatory and licensing fees on hydro units. They also budget safety items, unit availability and outage repair costs. Fossil/hydro has a few major capital items, such as the Hydro Station five tunnel repair, over the next three or four years.

For the Allegheny gas turbine, the budget coordinator receives the budget from the contract operator, then discusses with Company engineers. For hydro, operating expenses include FERC fees and headwater fees. Payroll and benefits are large expenses. The Auburn gas turbine is rented, and the rental cost must be included in the budget.

Once the bottom-up budget has been approved by the manager, it is sent to New York planning and control, then discussed and loaded into SAP. A budget summary from SAP is a key output of the process.

vi. General Services

The general services process for bottom-up budgeting begins with a budget meeting where year-to-date results are reviewed. Given what has occurred in the current year, the budget coordinator's goal is for the following year's budget to remain flat, and not specifically increase or decrease. Meetings are then held with managers to review their individual budget proposals and to draft a total budget for general services. For all expenses other than fuel, a total budget that is flat in comparison to the current year is sent to IUMC.

Labor comprises the primary operating expense for general services; managers provide the headcount and HR provides the related expenditure amounts. Managers are asked to provide entries for overtime and for "secondary labor movements," which are for shared employees who make time allocations to other companies. These labor allocations are made to the utility operating companies, but not specific to the gas and electric business units. Managers also budget for outside services, including contractors, rentals, short-term labor, and materials. They use historical levels plus additional certifications or parts that may be necessary. Fleet is budgeted in accordance with history and the age of the fleet. Fuel expense is partially hedged through a contractor for 50 percent of the next month's consumption to decrease volatility.

IUMC control performs budget cutting and revisions to the bottom-up budget, and makes cuts as they see fit. After the revisions, IUMC loads the budget into SAP. According to the budget coordinator, IUMC does not provide specific budget targets to general services.

c. O&M Budget Variances, 2006-2010

The tables for NYSEG and RG&E below provide comparisons of the "Plan" approved by executive management and the Board of Directors prior to the start of the budget year versus actual expenses experienced during the years 2006-2010.

NYSEG O&M Expenses Plan vs. Actual (Electric and Gas)

	2006		2007		2008		2009		2010	
Category	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan
Regular Labor	124,293	127,821	122,947	122,720	125,812	118,173	130,140	126,690	108,184	131,036
Overtime Labor	30,172	12,823	16,485	6,659	27,422	14,574	15,512	25,276	19,198	19,302
Employee Benefits	12,402	27,057	7,353	23,160	(2,060)	8,203	26,339	2,901	61,038	53,431
Other Compensation	1,124	1,160	1,549	1,168	1,939	2,166	167	1,410	69	147
Outside Services	47,602	51,450	55,584	64,772	70,387	61,138	75,172	74,313	86,234	87,205
EEMC Charges	15,573	18,078	17,933	17,690	16,952	17,612	18,421	15,474	-	14,422
USS Charges	33,396	35,844	33,237	35,860	34,241	36,068	32,469	36,602	44,998	32,787
Uncollectibles	27,854	16,821	17,820	15,600	24,652	20,001	17,375	15,701	16,075	21,120
Materials	9,992	4,584	10,203	8,071	12,974	7,220	9,769	6,776	8,841	7,019
Rents - Leases	2,987	3,796	4,218	3,502	4,011	4,230	4,223	3,753	4,120	3,366
Fuel	32	70	57	-	40	28	65	36	22	30
Corporate Insurance	3,059	3,135	3,235	3,001	3,437	4,131	3,279	3,682	2,905	3,168
Injury Damages	3,256	1,039	3,438	864	(1,740)	882	(565)	537	814	1,138
Travel	4,075	4,838	2,653	3,207	5,142	2,425	2,944	2,533	3,452	2,573
Other General Expense	46,338	40,480	6,662	32,460	1,349	24,709	36,465	29,800	12,237	68,700
Transportation	15,168	15,109	16,955	14,835	16,236	14,963	18,627	18,397	20,224	19,937
Vehicle Depreciation							-	7	-	7
Regulatory Expense	914	1,404	899	1,279	605	785	416	777	0	664
Collection Expense	1,539	838	1,272	1,028	1,003	1,573	753	1,200	1,864	5,395
Regulatory Assessment	5,160	5,445	26,653	5,466	5,621	6,541	38,264	6,286	42,928	49,192
Regulatory Amortization	(11,390)	(22,579)	-	(9,486)	164,761	-	8,315	-	17,183	4,968
Transmission Wheeling	6,023	7,503	5,593	5,959	6,183	6,537	7,291	6,880	6,461	9,730
Purchase Power	-	624							3,228	-
Other	479	1,504	(12)	-	(106)	23	2	-	(2)	-
Total Operating Expenses	380,048	358,843	354,735	357,814	518,862	351,982	445,443	379,029	460,075	535,337
O&M Variance Percentage	5.91%		-0.86%		47.41%		17.52%		-14.06%	

RG&E O&M Expenses Plan vs. Actual

	2006		2007		2008		2009		2010	
Category	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan
Regular Labor	54,421	52,797	54,222	54,582	56,212	54,154	51,842	50,892	46,806	54,182
Overtime Labor	5,987	5,992	6,042	7,039	7,125	4,107	5,647	10,017	5,194	4,473
Employee Benefits	(231)	10,287	(3,039)	1,492	(6,478)	(4,024)	17,105	(6,469)	20,445	18,489
Other Compensation	1,000	1,116	964	1,097	931	1,506	168	906	60	157
Outside Services	27,411	32,807	38,492	36,068	37,689	38,144	29,296	41,697	38,571	48,937
EEMC Charges	7,469	8,510	9,164	7,912	8,244	8,293	12,687	6,977	-	8,056
USS Charges	15,692	17,644	16,503	17,893	15,449	17,545	17,513	16,689	22,922	16,776
Uncollectibles	8,233	12,045	13,531	10,200	25,022	10,200	19,982	11,100	14,348	24,924
Materials	5,755	4,698	5,079	4,754	4,877	4,508	4,440	4,231	3,875	4,430
Rents - Leases	4,087	4,071	4,226	4,058	4,144	3,983	4,293	4,073	3,922	4,146
Fuel	1	-	(110)	-	2	5	10	1	4	1
Corporate Insurance	(510)	(258)	(783)	(415)	(977)	(540)	(29)	(672)	1,533	1,170
Injury Damages	1,164	400	117	215	311	215	(27)	115	427	192
Travel	829	1,406	673	1,183	994	1,280	678	1,038	589	957
Other General Expense	20,132	4,779	15,701	16,404	22,770	26,902	15,626	42,180	20,051	30,736
Transportation	4,201	4,393	4,340	5,415	4,743	5,404	4,757	5,470	5,702	5,425
Regulatory Expense	725	557	(81)	375	(10)	18	(4)	14	(6)	3
Collection Expense	594	662	742	965	1,051	1,150	678	1,005	1,715	3,433
Regulatory Assessment	2,489	2,476	10,285	2,623	3,292	3,791	23,445	3,971	26,576	30,007
Regulatory Amortization	47,997	55,954	54,588	51,452	149,614	39,201	49,079	40,223	29,165	39,225
Transmission Wheeling	320	320	320	320	320	320	320	320	320	330
Purchase Power	9,222	2,072	9,239	9,222	9,222	9,222	-	9,222	6	-
Electric Generation	4,494	1,986	21	-	5	-	-	-	-	-
Electric Supply	-	-	-	-	4	8	-	-	-	-
Disposition of Property	-	-	4	-	-	-	135	-	-	-
Other	207	-	(873)	1	(27)	1	1	(1,590)	1	0
Total Operating Expenses	**221,686**	**224,712**	**239,366**	**232,856**	**344,526**	**225,394**	**257,642**	**241,410**	**242,225**	**296,049**
O&M Variance Percentage	-1.35%		2.80%		52.86%		6.72%		-18.18%	

4. Management Reporting

IUSA budget management reporting occurs in two different formats for specific audiences. Monthly financial performance reporting is targeted for Company executives, upper management and the IUSA and New York Boards. The budget variance system provides more detailed budget information for departmental managers and vice presidents, project managers and capital program managers. Both systems provide performance information as compared to the budget for both capital and O&M expenditures.

The management reporting and budget variance processes are managed by IUMC administration and control and the New York controller's office. IUMC generates variance report packages for each vice president and manager. The reports may vary in content depending on the specific function. Most managers and vice presidents receive variance reports that are focused on the operating expense performance under their control. Project managers in the engineering organization receive reports on capital expenditure projects.

The monthly variance reports are provided on the eighth work day of each month. The functional areas are asked to provide a preliminary analysis on variances from the budget of more than 10 percent above or below the budget, or variances of more than $100,000. Managers must determine why variances have occurred, and the vice president or managers are to report at a monthly budget meeting on approximately the 10th through 12th work day of the month. The analyses of variances provided by each functional area are discussed, and the budget managers assist in determining solutions for mitigating variances. "Closing calls" are also held with managers to discuss preliminary results as of the first day of the month and also after closing on day eight or nine. Variance explanations are compiled by the New York controller's group for use by IUMC control in explaining financial results.

IUMC control is responsible for the income statement, balance sheet, cash flow statement and capital report for each of the following entities: NYSEG electric and gas, RG&E electric and gas, CMP electric, and IUSA Total. IUMC also provides the consolidation of the financials of all IUSA companies. The management variance reports are finalized and feed it into the performance management reports (PMRs) at the operating company level. The PMRs include income statements, balance sheets, financings and cash flow statements at business unit, OpCo and IUSA levels. PMRs also include an OpCo expense report prepared by The New York controller's group. The PMRs include financial statements in GAAP accounting as well as in IFRS international accounting standards. The external report that is sent to Iberdrola SA is in IFRS accounting format.

a. Monthly Financial Reports

The chart below is an example of the monthly financial performance report for NYSEG (total company) for September 2011.

NYSEG Financial Report September 2011

RESULTS (thousands USD)	Reported Sep-11	Budget Sep-11	Var Act-Bgt	% Act-Bgt		Actual Sep-10	% 11-10		Rev2 2011	Budget 2011	% F-Bg		Year 2010	% F- 10
Net Sales	1,235,496	1,055,097	180,400	17.1%	n	1,175,923	5.1%	n	1,497,543	1,407,502	6.4%	n	1,659,476	-9.8%
Procurements	-567,384	-391,190	-176,195	45.0%	n	-579,372	-2.1%	n	-593,510	-527,486	12.5%	n	-811,411	-26.9%
Gross Margin	**668,112**	**663,907**	**4,205**	**0.6%**	n	**596,551**	**12.0%**	n	**904,033**	**880,016**	**2.7%**	n	**848,066**	**6.6%**
-Personnel	-222,328	-208,774	-13,554	6.5%	n	-185,113	20.1%	n	-299,279	-276,459	8.3%	n	-254,244	17.7%
-Capitalized Costs	53,282	46,088	7,194	15.6%	n	33,238	60.3%	n	82,189	60,356	36.2%	n	54,964	49.5%
-External Services	-139,081	-137,286	-1,795	1.3%	n	-93,927	48.1%	n	-191,992	-182,384	5.3%	n	-175,078	9.7%
-Other Operating Income	633	233	400	171.8%	n	598	5.9%	n	457	311	46.7%	n	281	62.5%
Net Operating Expenses	-307,495	-299,739	-7,755	2.6%	n	-245,204	25.4%	n	-408,625	-398,176	2.6%	n	-374,077	9.2%
Taxes other than income tax	-115,216	-114,750	-466	0.4%	n	-115,708	-0.4%	n	-157,837	-153,291	3.0%	n	-154,630	2.1%
EBITDA	**245,401**	**249,418**	**-4,016**	**-1.6%**	n	**235,639**	**4.1%**	n	**337,571**	**328,549**	**2.7%**	n	**319,359**	**5.7%**
Amortisation and Provisions	-108,159	-103,066	-5,093	4.9%	n	-106,012	2.0%	n	-138,736	-137,936	0.6%	n	-135,236	2.6%
EBIT / Profit from Operations	**137,242**	**146,352**	**-9,110**	**-6.2%**	n	**129,628**	**5.9%**	n	**198,835**	**190,612**	**4.3%**	n	**184,123**	**8.0%**
Results non-current assets	12,410	10,979	1,431	13.0%	n	0	n/a	n	9,851	10,979	-10.3%	n	0	n/a
Operating Result	**149,652**	**157,331**	**-7,679**	**-4.9%**	n	**129,628**	**15.4%**	n	**208,686**	**201,591**	**3.5%**	n	**184,123**	**13.3%**
Results Companies Equity	0	0	0	n/a	n	0	n/a	n	0	0	n/a	n	0	n/a
B.A.I.I.	**149,652**	**157,331**	**-7,679**	**-4.9%**	n	**129,628**	**15.4%**	n	**208,686**	**201,591**	**3.5%**	n	**184,123**	**13.3%**
Finance Expenses	-105,343	-93,028	-12,315	13.2%	n	-100,623	4.7%	n	-140,846	-123,951	13.6%	n	-130,475	7.9%
Finance Income	96,489	84,116	12,373	14.7%	n	86,888	11.1%	n	123,986	112,830	9.9%	n	109,008	13.7%
EBT	**140,798**	**148,419**	**-7,621**	**-5.1%**	n	**115,892**	**21.5%**	n	**191,826**	**190,471**	**0.7%**	n	**162,656**	**17.9%**
Income Taxes	-54,349	-55,136	787	-1.4%	n	-43,011	26.4%	n	-75,919	-72,040	5.4%	n	-62,171	22.1%
Minority Income	-297	-297	0	0.0%	n	-297	0.0%	n	-396	-396	0.0%	n	-396	0.0%
Net Profit	**86,152**	**92,985**	**-6,834**	**-7.3%**	n	**72,584**	**18.7%**	n	**115,511**	**118,034**	**-2.1%**	n	**100,089**	**15.4%**
OPERATIONAL INDICATORS	**Reported Sep-11**	**Budget Sep-11**	**Var Act-Bgt**	**% Act-Bgt**		**Actual Sep-10**	**% 11-10**		**Rev2 2011**	**Budget 2011**	**% F-Bg**		**Year 2010**	**% F- 10**
Distributed Energy (GWh)	22,953	22,201	752	3.4%	n	21,882	4.9%	n	30,876	30,623	0.8%	n	30,783	0.3%
Residential	8,394	8,334	59	0.7%	n	8,243	1.8%	n	11,654	11,604	0.4%	n	11,827	-1.5%
Commercial	4,113	3,980	132	3.3%	n	4,037	1.9%	n	5,283	5,268	0.3%	n	5,415	-2.4%
Industrial	2,441	2,347	94	4.0%	n	2,551	-4.3%	n	3,139	3,131	0.3%	n	3,301	-4.9%
Other	8,006	7,539	467	6.2%	n	7,051	13.5%	n	10,800	10,620	1.7%	n	10,240	5.5%
Customers (n)	1,141,038	1,144,297	(3,259)	-0.3%	n	1,138,041	0.3%	n	1,144,203	1,144,203	0.0%	n	1,139,106	0.4%

Actual vs. Budget

Electric:

GM:	-4.1	Net Opex:	#	Other Exp:	-5.0
Base delivery - service classes not subject to RDM	2.6	IUMC allocated costs	#	Earnings neutral items - GRT	0.6
Base delivery - unbilled not subject to RDM	-3.2	Earnings neutral items - PBA amortization	#	Earnings neutral items - Property taxes - deferral in revenue	-2.4
Earnings neutral items - GRT	-0.8	Earnings neutral items - rate case expenses subject to deferral	#	Sales and Use taxes	0.2
Earnings neutral items - property tax deferral & TSAS	1.7	Timing on expenditures & delays in work due to weather	#	Uncollectibles - inc. in DPA results and a dec. to actual w/c	1.2
Earnings neutral items - PBA amortization	4.7	Pension/OPEB - part of deferral moved to finance costs/income	#	Uncollectibles - reserve adjustments - increase in DPA bala	-4.1
Earnings neutral items - all other	-3.1	OPEB prior year correction	#	Depreciation	-0.3
Earnings sharing estimate	-3.9			Injuries & damages reserve - adj. based on outstanding cla	-0.1
Property rental - billing to Verizon	2.8				
SBC unbilled - prior year	-1.4				
Economic development deferral correction - prior yr	-1.3				
JP combined items - add to ASGA	-1.5				
Miscellaneous billing	-0.8				

Gas:

GM:	8.6	Net Opex:	#	Other Exp:	1.6
Base delivery - service classes not subject to RDM	-0.4	IUMC allocated costs	#	Earnings neutral items - GRT	-0.2
Base delivery - unbilled not subject to RDM	-1.3	Earnings neutral items - PBA amortization	#	Earnings neutral items - regulatory assessment	0.8
Earnings neutral items - GRT	0.0	Earnings neutral items - transition surcharge	#	Earnings neutral items - Property taxes - deferral in revenue	0.4
Earnings neutral items - property tax deferral & TSAS	-1.3	Earnings neutral items - rate case expenses subject to deferral	#	Sales and Use taxes	0.2
Earnings neutral items - PBA amortization	13.3	Timing on expenditures & delays in work due to weather	#	Uncollects. - inc. in DPA results in a dec. to actual write-of	2.0
Earnings neutral items - transition surcharge	0.3	Pension/OPEB - part of deferral moved to finance costs/income	#	Uncollectibles - reserve adjustments - increase in DPA bala	-1.7
Earnings neutral items - all other	-0.4	OPEB prior year correction	#	Depreciation	-0.2
Timing difference in the GSC deferral	0.3			Injuries & damages reserve - adj. based on outstanding cla	-0.2
Errors in the plan in the TSAS deferral & pipeline refur	-1.8			Injuries & damages reserve - accrual for gas explosion	-1.0
Economic development deferral correction - prior year	-0.2			Seneca Sale Gain	1.4

Actual vs. Prior Year

Electric:

GM:	53.8	Net Opex:	#	Other Exp:	0.9
Rate case impact	58.8	Labor/headcount - net of pension variances	#	Earnings neutral items - GRT	0.6
Earnings neutral items - GRT	-0.6	Increase in capex. staff costs due to the increase in the capex. prog	#	Earnings neutral items - TSAS - lower assessible revenues	2.4
Earnings neutral items - TSAS - lower assessible revs	-2.5	Rate case impact - amortizations	#	Property taxes - deferral in revenue since 9/2010	-4.0
Earnings neutral items - all other	-0.7	Rate case impact - increase in environmental threshold	#	Sales and Use taxes	0.2
Miscellaneous billing - primarily pole attachments to Ve	2.7	The remaining var. is timing on how costs were spent last yr vs this	#	Uncollectibles	-0.1
Earnings sharing estimate	-3.9			Uncollectibles - reserve adjustments	1.3
				Depreciation - increased capital spending	0.4
				Vehicle Depreciation	0.2
				Injuries & damages reserve - adj. based on outstanding cla	0.0

Gas:

GM:	17.8	Net Opex:	#	Other Exp:	13.5
Rate case impact - estimate	18.3	Labor/headcount - net of pension variances	#	Earnings neutral items - GRT	-0.1
Earnings neutral items - GRT	0.0	Increase in capitalized staff costs	#	Earnings neutral items - regulatory assess - lower assessible	1.4
Earnings neutral items - TSAS - lower assessible reven	-1.7	Rate case impact - amortizations	#	Property taxes - deferral in revenue since 9/2010	0.2
Earnings neutral items - transition surcharge	1.0	Rate case impact - increase in environmental threshold	#	Rate case impact - property tax amortization	-0.4
Earnings neutral items - all other	0.3	The remaining var. is timing on how costs were spent last yr vs this	#	Sales and Use taxes	0.2
				Uncollectibles	0.5
				Uncollectibles - reserve adjustments	0.1
				Depreciation - change in depreciation rates	0.4
				Injuries & damages reserve - adj. based on outstanding cla	-0.2
				Injuries & damages reserve - accrual for gas explosion	-1.0
				Seneca Sale	12.4

NYSEG Margin - Actual vs Plan - Reported Sept 2011		
	NYSEG Electric	NYSEG Gas
RDM Impacts:		
Service classes not subject to RDM	2,635	(386)
Net unbilled not subject to RDM	(3,151)	(1,258)
	(516)	**(1,644)**
Earnings Neutral Items:		
Offset in Net Operating Expense	1,584	13,288
Offset in Other Taxes	920	(1,356)
	2,504	**11,932**
Other:		
PY economic dev deferral correction	(1,290)	(242)
PY ASGA amortization true-up	-	-
SBC unbilled - program suspended	(1,400)	-
Misc billing -primarily pole rentals	2,044	-
Timing on the GSC deferral	-	347
JP combined items - add to ASGA	(1,500)	-
Miscellaneous Billing	-	-
Earnings Sharing	(3,900)	-
MFC	(376)	320
Planning Errors	-	(1,824)
All Other	(84)	(166)
	(6,506)	**(1,565)**
Gross Margin Variance	**(4,518)**	**8,723**

The financial reports to executives and management provide monthly and year-to-date financial performance for the utility businesses. Margins, EBITDA, EBIT and net profit levels for each of the electric and gas business units are provided on a year-to-date basis for the current month, and for the comparable period in the previous calendar year. Operating revenues, operating expenses and operating income are also provided for the current month and year-to-date for each of the business units.

The monthly financial reports also include extensive budget performance information for operating expenses, as shown above. Actual operating expenses are compared to the budget and the previous year's actual expenditures for both the current month and for the year-to-date. The performance to budget for O&M expenses are also provided for each major organization and the major departments within each organization. Analysis of the significant variations from budget in departmental expenses for both the current month and the year-to-date is provided to supplement the budget performance reports.

b. Variance Reporting System

This system includes detailed information on budgets and actual performance for the departmental O&M budgets. IUMC control coordinates the reporting of monthly actual information and variance analyses, and has the responsibility to get variance explanations from managers and a detailed breakdown of the variances. They also prepare plans to remedy budget variances, and provide analyses of how the budget variances will impact the remainder of the budget year. The chart below is an example of the September 2011 variance report for NYSEG Engineering & Delivery.

Fiscal Year	2011	P11				P11				P11
Account Category	**September MTD Actual**	**September MTD Plan**	**Var**	**%**	**September YTD Actual**	**September YTD Plan**	**Var**	**%**	**Variance Explanation**	**Fiscal Year Plan**
Regular Time	411,317	340,797	(70,520)	-20.7%	3,268,572	2,481,373	(787,199)	-31.7%	Plan # below actual FTE's	3,155,373
Overtime	113,434	7,891	(105,544)	-1337.6%	406,037	130,421	(275,616)	-211.3%	More OT charged than planned	146,599
Other Compensation	3,321	455	(2,866)	-629.9%	4,776	3,495	(1,281)	-36.6%		4,660
Other Compensation	3,321	250	(3,071)	-1228.3%	4,748	1,650	(3,098)	-187.7%		2,200
Bene R&R Non-Cash	0	205	205	100.0%	28	1,845	1,817	98.5%		2,460
Employer SSI Costs	14,384	17,706	3,322	18.8%	148,543	117,944	(30,599)	-25.9%		143,119
Total Staff Costs	**542,456**	**366,849**	**(175,607)**	**-47.9%**	**3,827,929**	**2,733,233**	**(1,094,695)**	**-40.1%**		**3,449,752**
Regular Time	(290,471)	(93,741)	196,730	-209.9%	(1,546,450)	(845,335)	701,115	-82.9%	More moving to capital than planned	(1,127,088)
Overtime	(48,183)	(8,766)	39,417	-449.7%	(281,795)	(79,027)	202,768	-256.6%	More moving to capital than planned	(105,325)
Other Compensation	0	0	0	0.0%	0	0	0	0.0%		0
Employer SSI Costs			0	0.0%			0	0.0%		
Capitalized Staff Costs	**(338,654)**	**(102,507)**	**236,147**	**-230.4%**	**(1,828,245)**	**(924,362)**	**903,883**	**-97.8%**		**(1,232,413)**
Total Staff Costs	**203,802**	**264,342**	**60,540**	**22.9%**	**1,999,684**	**1,808,871**	**(190,813)**	**-10.5%**		**2,217,339**
Collection Expense	0	0	0	0.0%	0	0	0	0.0%		0
Contractors	3,620,460	2,513,783	(1,106,676)	-44.0%	23,200,676	28,127,840	4,927,164	17.5%	Money budgeted for contractors to support ProjectWise implementation. Project delayed and will not start until 12/7/11, Veg Mgmt Mitigation plans in place- will be on track 12/31.	35,644,600
Corporate Insurance	0	0	0	0.0%	0	0	0	0.0%		0
Dispatch	0	0	0	0.0%	0	0	0	0.0%		0
Employee Related	18,109	14,773	(3,335)	-22.6%	115,198	129,110	13,912	10.8%	All travel BTR for Sept not submitted, Cat.6 in Oct.	171,780
Fuel	96	63	(34)	-54.0%	96	563	466	82.9%		750
Materials	6,737	2,017	(4,720)	-234.0%	9,252	18,150	8,898	49.0%	Materials decreased in Rev 3 expected to spend in 4th quarter	24,200
Company Use	0	0	0	0.0%	0	0	0	0.0%		0
Accounting Deferred	0	0	0	0.0%	0	0	0	0.0%		0
Capital Related	0	350	350	100.0%	26,627	3,150	(23,477)	-745.3%	Tele Atals licensing fees, license renewals, railway fees, hardware support HP printers (OCE TDS 700 Copier)	4,200
Fees	153	0	(153)	0.0%	7,494	0	(7,494)	0.0%		20,000
Installation Credits	0	0	0	0.0%	0	0	0	0.0%		0
Information Technology	13,290	29,635	16,345	55.2%	131,107	328,690	197,583	60.1%	Money budgeted for software required for ProjectWise implementation. Project delayed and will not start until 12/7/11. Veg Mgmt Transmission project is on revised schedule.	428,595
Other General	25,059	18,035	(7,025)	-38.9%	84,943	175,628	90,684	51.6%	Outsourcing some work a factor. Office expenses less then forecast and expected to increase in 4th quarter.	231,088
Planning	0	0	0	0.0%	0	0	0	0.0%		0
Rents Leases	9,620	2,917	(6,704)	-229.8%	59,363	26,250	(33,113)	-126.1%	Copier lease	35,000
Regulatory Expense	0	0	0	0.0%	0	0	0	0.0%		0
Corporate Expense	0	0	0	0.0%	0	0	0	0.0%		0
Total Outside Services	**3,693,524**	**2,581,572**	**(1,111,952)**	**-43.1%**	**23,634,757**	**28,809,380**	**5,174,623**	**18.0%**		**36,560,213**
Total	**3,897,326**	**2,845,915**	**(1,051,411)**	**-36.9%**	**25,634,441**	**30,618,251**	**4,983,810**	**16.3%**		**38,777,552**

c. Capital Reports

The Company has established a refined process in 2011 to provide more detailed review and analysis of the capital budget during the budget year called the IUSA Capital Investment Reports. Capital projects and programs are tracked individually, as well as by business unit, OpCo and in total. Variances from budget and their causes are tracked, i.e. system events, failures or changes in project scope or costs. The more detailed reports and review process have been established to provide better information on changes in capital plans and spending. The following is a summary page from the new capital reports.

2011 Capital Investment Variances
($000s)
September Results

	2011 Plan (A)	YTD Actual (B)	YTD Plan (C)	Variance (B-C)
NYSEG Electric	$ 174,188	$ 110,683	$ 141,026	$ (30,343)
RGE Electric	171,497	78,059	132,923	(54,864)
Subtotal NY Electric	345,685	188,742	273,949	(85,207)
NYSEG Gas	45,200	25,362	33,560	(8,198)
RGE Gas	34,403	22,431	26,015	(3,584)
Subtotal NY Gas	79,603	47,793	59,575	(11,782)
CMP Transmission	87,072	45,512	57,232	(11,720)
CMP Distribution	57,953	33,867	45,197	(11,330)
CMP T&D	145,025	79,379	102,429	(23,050)
All Other IUSA Capital	15,658	8,525	13,309	(4,784)
Total	585,971	324,439	449,262	(124,823)
MPRP	309,270	211,627	231,281	(19,654)
AMI Project - Net	45,683	28,958	39,085	(10,127)
Grand Total	$ 940,924	$ 565,024	$ 719,628	$ (154,604)

d. Audited Feedback Loops

Best practice call for the use of experience to inform future budgeting efforts. Liberty reviewed and questioned the existence of structured feedback processes intended to use prior results (*e.g.*, budgeted versus actual performance at the detailed, or component, level) to improve the quality of budgeting processes. IUSA does not use such processes currently. Others use such feedback loops to evaluate the quality of project analysis and cost estimate information and to constantly improve decision information. Evaluations of the effectiveness of past project prioritization efforts also may be used to improve decision making information.

5. Strategic Plans and Forecasts

IUMC control was asked about the various types of longer-term, strategic forecasting performed and the number of years of the forecasts. The Company reported that forecasting is currently performed in three formats: one year budgeting, a three-year forecast, and a ten-year forecast. The three-year forecast is new and is being refined; it should provide the foundation for three-year rate plans in the future. The three-year forecast is currently aligned with the approved rate plan, which runs from 2011 through 2013. A new version of the three-year plan was recently completed.

The budgets have included a risk overlay on completed and authorized budgets for the past few years. Risks evaluated include regulatory penalties, cash impacts such as regulatory deferrals, service territory economic changes, and storm damages. The financial performance in the baseline budget is assessed for how much it would be impacted by various risk factors.

The ten-year forecast is not yet fully developed. After the third year, a rough capital plan and the assumption of new forecasted rate plans every three years has been assumed.

C. Conclusions

1. NYSEG and RG&E have been unable to execute their capital expenditure plans on a timely basis, with significant problems in 2010 and 2011. *(Recommendation #1)*

NYSEG and RG&E have historically under-spent their Board-approved capital budgets by substantial margins. For the years 2007-2009, NYSEG recorded annual capital spending compared to budget of -15.3 percent, -28.2 percent, and -41.8 percent, respectively. RG&E recorded capital budget under-spending from 2006-2009 of -21.9 percent, -10.0 percent, -31.4 percent and -60.2 percent. These results are far above normal tolerances for total capital budget variances. Plus or minus five percent is an industry performance rule-of-thumb. Some utilities have performance targets of two percent or less annual variances in this crucial corporate performance measurement.

Capital spending in the 2010 and 2011 budget years was also shaping up to be far behind plan. However, both Companies added new projects and additional spending near the end of each year to meet regulatory requirements and to bring capital spending to nearer budgeted levels.

<u>*2010 Capital Budgets*</u>

According to the capital expenditure conditions included in the September 2008 Iberdrola merger Order, for the years 2009 and 2010 NYSEG should make capital expenditures of no less than an average of $140 million per year for its electric system and no less than an average of $20 million per year for its gas system. For the years 2009 and 2010, RG&E should make capital expenditures of no less than an average of $90 million per year for its electric system and no less than an average of $20 million per year for its gas system. In 2009, the Companies filed a request with the NYPSC to meet the regulatory requirement in three years instead of two. The commission rejected the request in April 2010.

Company managers report that when the 2010 capital budget was assembled in late 2009, a greater capital spend and more progress on capital projects was expected by the end of 2009 than actually occurred. The Companies also anticipated a positive outcome for their capital spending deferral request. However, the April 2010 management financial reports for IUSA included the following explanation:

> *Based on discussions that occurred at the last NYPSC Open Session, the companies expect that we will be directed to either meet the minimum capital spending required under the merger order for 2009-2010, or calculate the revenue requirement associated with the underspending, and provide an assessment of the considerations involved in that decision, including the benefits*

> *to customers. In the event of the latter approach, the Companies will be required to file this information by January 31, 2011.*

In each month's management financial reports in 2010, both Companies fell progressively further behind in executing approved capital projects as well as in capital dollars expended. (Appendix A, attached to this chapter, is a recap of the monthly capital expenditure variance explanations from these reports.) The October variance analysis included the following explanation of the under-spending and plans to mitigate to reach merger Order requirements:

> *Pursuant to an April 30, 2010 NY PSC order, the NY companies were directed to meet the total minimum capital spend for 2009-2010 required under the merger order, or be subject to a potential penalty based on a defined formula. Based on the 2009 actual ($145 M) and 2010 plan ($223 M) capital spend amounts, the NY Companies would fall $92 million below the merger order level for electric capital. Through September 2010, electric capital spend is $130 M, behind plan by about $40 million. The Engineering and Asset Management group has worked with an outside consultant and is planning to spend additional capital through the remainder of 2010, with monthly spend projected October through December at $26 M, $43 M, and $57 M.*

NYSEG and RG&E needed to add additional electric capital spending beyond their capital plans of around $132 million in only three months before the end of 2010. The Companies received Board approval of "revised" capital plans on September 29, 2010. NYSEG spent more than the merger Order amounts for both electric and gas by the end of 2010; RG&E spent slightly less for electric but met the Order requirements for gas. Details of the additional capital spending projects and amounts are included in Conclusion 3 below.

<u>*2011 Capital Budgets*</u>

IUSA has developed a new "Capital Investment Plan Report" for 2011 that is issued monthly to capital managers and executives to track projects more closely. The report is well organized and informative, with graphics and individual project details as well as summaries of progress by business unit. Project managers are now asked to "refresh estimates" every month, and more emphasis is being placed on project timing.

In spite of these efforts, project progress and capital spending levels were again lagging well behind budget through September 2011. (Appendix B provides month-by-month analysis of 2011 capital spending). Project delays are again rampant, in addition to weather delays and a major tropical storm in September. However, the amount of the variances progressively increases in each month, similar to 2010.

The following is the monthly report for August 2010, before the major tropical storm (NY projects only):

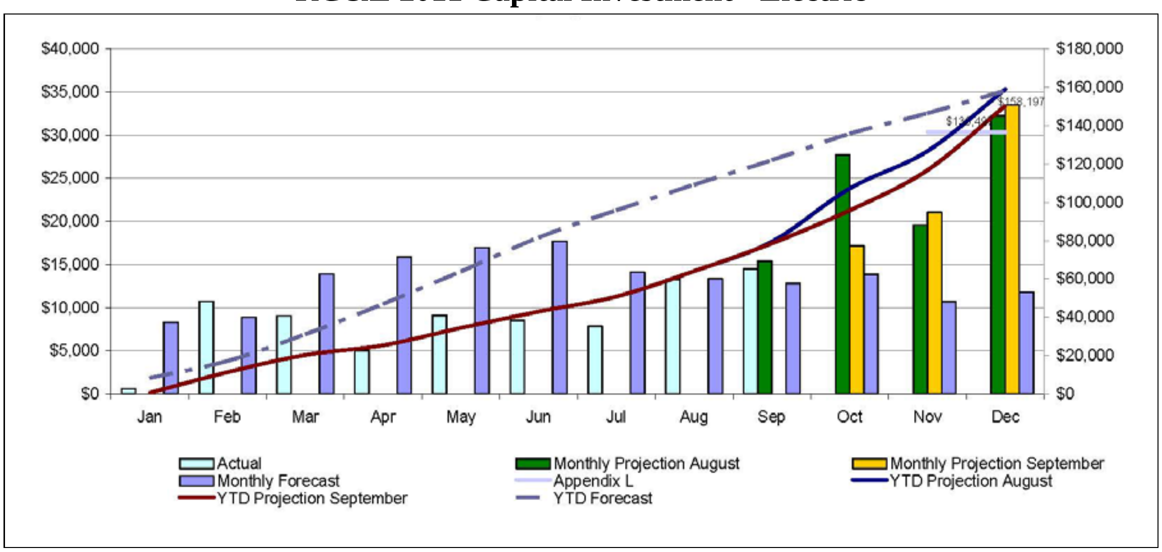
> *The August, 2011 year to date capital variance is under plan $163M. The New York electrical variances of $75M represent Hydro Projects under plan by*

($15.5) which includes Station 5 at RGE for multiple projects including the Station 5 tunnel relining where mobilization has begun, NYSEG's Corning Valley Project ($7.2M), Government Road Projects at RGE ($4.5M) and Substation Projects ($25.8M) all running under plan due to project delays. Other electric projects for both NYSEG and RGE are under plan ($20M) through August, 2011. Commencement of delayed projects has accelerated construction projects due to awarded contracts.

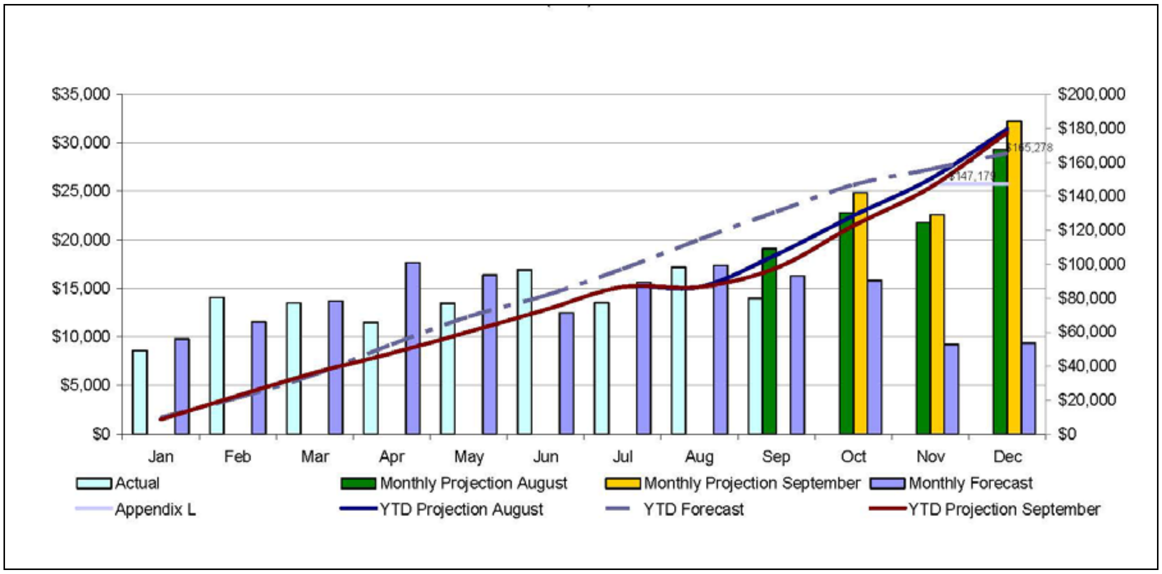
Other capital projects are below plan $20M due to transformer purchases under plan ($2.5M), fleet and general equipment deliveries scheduled for Q3 and Q4 under by ($6M), reinforcement and other projects are under due to engineering delays in issuing the RFP, permitting issues and award of construction contract later than first expected. For NYSEG and RGE Gas segments, a total variance under budget remains at ($16M) for August. Timing of meter and regulator purchases ($2.9M), under run of new business ($3.8M), transmission mains and leak prone gas main and services replacement program is under plan ($6M) due to weather delays in the winter months and permit delays from municipalities but gas construction projects are underway and are projected to equal forecast by year end.

The charts below show graphically the NYSEG and RG&E electric capital budgets versus actual spending in each month in 2011, and monthly changes in the expectations for the remainder of the year. Note that as the Companies fall further behind budget in electrical spending, the difference has been loaded into the remaining months of the year. Spending in December for NYSEG, for instance, is more than 300 percent of the budgeted amount by the September report.

RG&E 2011 Capital Investment - Electric



NYSEG 2011 Capital Investment - Electric



The NYSEG and RG&E Boards have belatedly approved additional 2011 electric projects and spending of about $23 million for each of the Companies in response to the spending shortfalls. Liberty concludes that that NYSEG and RG&E continue to be unable to execute their capital budgets, especially on the electric side, as of September 2011.

2. IUSA does not provide adequate capital project designs, cost estimating and project planning to support the timely execution of the NYSEG and RG&E capital budgets. *(Recommendation #1)*

Weaknesses in its current capital budgeting methods have routinely been producing "catch-up" spending programs that engender inefficiency, as noted in Recommendation 1. Projects often are in an unrefined state when incorporated into budgets, spending rates versus monthly budgets are unmet, and projects scheduled for completion in the current year continue to carry over to the next year too frequently. Factors such as these offer strong indicators of inefficiencies in capital planning processes.

In both 2010 and 2011, large under-spends and lack of progress in executing the approved capital budget Plan has caused NYSEG and RG&E to add new, previously unapproved projects to the months of September through December in attempts to meet the "total spending level" of approved capital expenditures. Liberty's observations and discussions with Company managers have identified the following specific causes of capital budget non-performance that are related to the budgeting process: (Note: The following apply to both electric and gas projects).

- Projects with "first estimates" and rudimentary designs (e.g., without technical specifications and site and equipment details) are often included in the capital budgets approved by senior management and the Boards of Directors; such estimates have insufficient accuracy ranges of +/- 25 to 40 percent.

- Work on refined designs and estimates is not started until after Investment Planning determines the "final" project list for senior management and Board approval, causing substantial delays in project initiation.
- The "pipeline" of designed and estimated capital projects is empty; a backlog of designed and estimated projects is required to improve capital spending efficiency.
- Project cash flow estimates have been overly optimistic and their accuracy has not been emphasized in project management, causing very poor performance to budget.
- The annual costs of multi-year projects appear in budgets approved and monitored by senior management and the Boards, but without visibility on what costs will be by month; this undermines the oversight role of the Boards and the ability to monitor progress against total project estimates.
- Engineering, design, and estimating of major infrastructure projects is insufficient to support inclusion of meaningful detail into new five-year and ten-year Capital Plans.

IUSA engineering management has recently reported that it is attempting to add an additional 25 percent (above budget) projects into the 2012 planning and budgeting "pipeline" to compensate for some of the problems and delays described above. At this time, the effect of such efforts is unknown.

3. NYSEG and RG&E have implemented expedited "CAPEX catch-up additions" to electric capital plans in both 2010 and 2011. The cost effectiveness of such expedited efforts is dubious. *(Recommendation # 1)*

The 2010 capital spending "shortfalls" identified in Conclusion 1 required IUSA engineering to develop new projects, as of June 2010, in order to meet capital spending targets from the merger Order. Additional capital projects and spending on capital programs was assembled and proposed to the NYSEG and RG&E Boards of Directors in September 2010. NYSEG and RG&E formed an "Incident Command Structure" that included operations' employees and focused on the proposed reliability investments. A report to the NYPSC in January 2011 on the capital spending required by the merger Order specifically described 2010 capital expenditures that were added to the capital plans to meet the Order requirements.

The following are the types of projects and amounts that were added to the capital plans for September-December 2010:

A. TDIRP – This category included substation breaker replacements, problem transmission pole replacement, and distribution improvements such as problem lines, circuits and transformers. Additional expenditures: NYSEG $31.2 million, RG&E $20.6 million.

B. Division Minors or Routines – These projects were performed by both Company linemen and contractors, and included pole replacements, re-conductoring, and line extensions. Much of the work was performed by the contractors. Additional expenditures: NYSEG $14.4 million; RG&E $1.3 million

C. Fleet – Fleet expenditures were cut drastically in 2009. Effectively, two years of fleet spending was performed in late 2010, including new single-bucket trucks. Additional expenditures: NYSEG $14.1 million; RG&E $2.1 million.

D. Incremental Projects in 2011 Rate Plan – Early work on the larger projects that were included in the 2011 rate plan. Engineering was performed, and required equipment purchased in the capital expenditure additions for 2010. Additional expenditures: NYSEG \$11.0 million; RG&E \$14.0 million.

E. NYSEG System Security and Electric GIS – 2011 rate plan spending was accelerated to commence in 2010. Additional expenditures: NYSEG: \$5.1 million.

The additional capital spending related to the categories above totaled \$75.8 million for NYSEG and \$38.0 million for NYSEG in 2010.

Since both the NYSEG and RG&E electric business units were again under-spending their capital budgets in the first half of 2011, IUSA again added additional projects to the budget to accelerate the capital spend in the second half of 2011. The additional projects were approved utilizing a post-budget authorization form ("PBAF") that is authorized by engineering management to make substantive changes to Board-approved projects. Since the asset management "health reports" were completed on three asset classes in June 2011, the spending additions were focused in three areas: over 100 additional substation breakers, \$15 million in additional distribution poles, and substation batteries and distribution problem circuit replacements. Gas operations also expanded the leak-prone replacement miles for 2011 completion, according to IUSA engineering management.

Liberty requested the following to document the information that the NYSEG and RG&E Boards received regarding these additions: "Please provide the presentations to the Boards of Directors to receive approval for the 2011 capital additions to the originally approved capital budgets." The presentation received indicated that NYSEG electric and RG&E electric were each expecting to spend an additional \$23 million on non-"Appendix L" projects in 2011. However, the additional funds to be spent were designated in the presentation for numerous smaller "projects," and not the TDIRP and reliability programs described above.

Weaknesses in IUSA's current capital budgeting methods have routinely been producing "catch-up" spending programs that engender inefficiency through additional overtime for both employees and contractors, as well as potential extra materials procurement charges due to expedited purchases. Liberty concludes that these weaknesses are strong indicators of inefficiencies in capital planning and expenditure processes.

4. The IUSA Board of Directors has not closely examined, approved, monitored nor taken necessary corrective action regarding the capital expenditures budgets of the utilities. *(Recommendation #3)*

The inaction of the IUSA Board of directors in the face of repeated large variances in capital budgets is unacceptable. The review, approval, and oversight of the capital expenditures budget form one of the most important sets of responsibilities of a board of directors. The Board has not focused on this crucial area, which has been very problematic at the New York utilities. Boards should be active in assuring not only that spending occurs at required levels, but that the money being spent is being spent effectively.

Poor performance in executing the capital expenditures budget, as approved by the Board, has not emerged suddenly at the end of the last two years. The Companies have substantially under-spent their electric capital budgets going back to at least 2006. Liberty's review of more recent data demonstrates that adverse trends were clear and had become alarming by mid-year in both 2010 and 2011. The utilities were clearly making progress at rates substantially less than required to meet expenditure and schedule targets. At this point, intervention by the Company Boards or the IUSA Board is called for.

The Boards have also not performed their capital-expenditure oversight role effectively. Liberty's review of presentations to the Boards regarding requests for authority to add projects and spending in 2010 and 2011 revealed neither substantive explanations of the reasons for the under-spending, nor expansive solutions and mitigation plans. Liberty can only conclude that the Boards were not well-informed of the issues involved, and have not become engaged directly and actively in identifying and implementing the changes required.

5. **NYSEG and RG&E 2010 capital budgets were not approved until September 29, 2010, almost 10 months after the budget year began and after significant capital spending had occurred.** *(Recommendation #3)*

Liberty's review of Boards of Directors' minutes related to budget approval noted that resolutions were not adopted to approve the 2010 budgets for either Company in late 2009 or early 2010. In fact, the September 29, 2010 Board minutes for NYSEG stated: "RESOLVED, that the 2010 capital budget as presented to this meeting (are) required to meet the merger order requirements and is hereby ratified."

Liberty requested clarification of this issue with the following Data Request (#1041):

> *Refer to the responses to Data Requests #150 and #151. The #150 response includes slides titled "Budget 2010, Board Meeting December 10th, 2009." However, the Board minutes in #151 do not include resolutions to approve the 2010 budget until the September 29, 2010 meeting. Please explain how NYSEG could legally operate and spend money without the Board approvals.*

The Company's response included the following statement:

> *In December 2009 the 2010 Budget, which included both the capital and operating budgets, was presented to the NYSEG and RGE Boards. The NYSEG and RGE Boards reviewed and approved the 2010 Budgets. Due to a Scribner's error the reference to the budget was not descriptive of the presentation made to the Board.*

However, the IUSA "Update to Self-Assessment," dated April 1, 2011 included the following self-assessment finding:

The 2010 capital budget was approved by the NYSEG and RG&E Board of Directors on September 29, 2010, nine months after the budget year began and significant capital spending was underway.

6. O&M budgets are effectively developed, coordinated and consolidated using consistent targets, formats and reports.

The O&M budget processes are well structured, coordinated and scheduled. Following the receipt of the budget guidelines in each budget-responsible organization, budgets are appropriately developed from the bottom-up. Budget coordinators in electric operations, engineering, gas operations, general services, IT, finance, regulatory, human resources, fossil/hydro, energy supply, public affairs, and customer service each develop “departmental budgets” that are submitted to the IUMC control and New York controller’s groups, who administer the processes. While specific O&M budget spending limitations are not expressly communicated, employees understand that departmental O&M budgets should be limited to the amount included in the last rate Order, which is appropriate.

Vice Presidents and managers review and approve their departmental budgets, which are coordinated for each functional area and submitted to the New York Controller’s office for review. The budgets for each area are then reviewed and approved by the New York Controller and the New York COO and President, and in turn, IUSA senior management and Board.

Liberty concludes that the budgeting processes for operating expenses for NYSEG and RG&E are well-organized and effective.

7. IUSA has effective management reporting processes and reports in place for both executive and manager levels to track, monitor and manage O&M expenditures. Budget variances are appropriately identified and evaluated.

IUSA’s management reporting occurs in two different formats within the SAP financial system, and they work together with common and mutually supportive information. Financial performance management reporting (“PMRs”) is targeted for Company executives, upper management and the Boards. The budget variance system provides more detailed operating budget information for departmental managers and vice presidents.

The monthly financial reports include extensive budget performance information for operating expenses. The performance to budget is provided for each business unit and for each OpCo. Analysis of the significant variations from budget in operating expenses is provided to supplement the budget performance reports; this analysis has been enhanced in the 2011 reports. The monthly financial reports also include analysis of rates of return versus regulatory budgets and regulatory allowed return on equity. The financial reports include key financial performance indicators on business unit, total Company and IUSA bases.

The budget variance reporting system includes detailed information on budgets and actual performance for the O&M budgets. IUMC control coordinates the reporting of monthly actual information and variance analyses. This group and the New York controller’s group have the responsibility to get variance explanations from managers and a detailed breakdown of the variances. The Company attempts to mitigate budget variances as they are recognized. The

IUMC control also coordinates three revisions of the budget during the year that includes actual results and revisions to the remainder of the budget year.

8. IUSA has not fully developed longer-term strategies, plans and forecasts that can be linked with three-year rate plans and the annual budget process. *(Recommendation #2)*

IUSA does not currently have an integrated, long-term strategic plan and forecast that sets forth "where the companies are going" regarding future infrastructure replacement and its effect on long-term electric reliability and related financial and rate impacts. IUSA’s planning and forecasting is currently performed in two formats: one year budgeting and a three-year forecast developed for rate planning purposes. The three-year forecast is new and is being refined; it should provide the foundation for three-year rate plans in the future. The ten-year forecast has not yet been developed past the third year. After its third year, a rough capital plan and the general assumption of new forecasted rate plans every three years has been assumed.

Formulating such long-term plans and forecasts is important for developing a consistent vision and planning linkage to three-year rate forecasts and annual budgets. A longer-term strategic plan that has been shared with the NYPSC and other stakeholders provides a touchstone and roadmap for preparing the shorter-term rate plans and budgets required to reach infrastructure and reliability investment goals. IUSA’s current plans and budgets are not specifically linked to a strategic plan to ensure that progress toward long-term system goals and objectives is being made, and that budgets and rate plans serve to support the systematic improvement of Company infrastructure.

9. IUSA identifies and initiates expenditure projects and programs with appropriate and consistent system modeling.

IUSA identifies required expenditures and capital projects using industry standard electric and gas system-specific modeling applications. Consistent engineering requirements models are utilized to identify component loadings and the requirements of the electric and gas systems.

The NYSEG/RG&E electric system planning department prepares ten-year reliability assessments that are updated biennially. The purpose of the ten-year studies is to identify the long-range system problems due to forced or maintenance outages that may occur on the NYSEG and RG&E transmission and sub-transmission systems and to recommend system reinforcements that would be required to correct these system problems. The key criteria for project identification and prioritization are megawatts of load lost, number of customers affected and hours of loss exposure.

The Stoner gas system planning model is utilized to identify low pressures and new load impacts and where reinforcements and replacements are required. These models analyze system pressure and flows to evaluate the impact of planned work, to plan for future infrastructure reinforcements, to evaluate the effects of new system loads, and to prepare for emergency contingencies. Another gas modeling effort is the gas mains replacement failure analysis model that predicts gas leaks and is used to build a main replacement plan.

10. IUSA does not have a common, company-wide analysis system to evaluate and prioritize projects. *(Recommendation #1)*

As noted previously, IUSA performs various types of engineering analyses to identify and justify projects and program expenditures for the capital budget. Engineering and gas operations each have methods for analyzing and prioritizing projects and expenditures that are unique to their organization and are adequate. On the other hand, IUSA does not currently have a higher-level, common method of analysis and prioritization that is used company-wide, which makes the allocation of available capital dollars among business units difficult. Since no common analysis has been applied, capital allocation decisions must be made based upon experience and more subjective prioritization methods. IUSA needs a common analysis method and metrics to be able to compare the relative merits of projects and expenditures.

Priorities are first based on rate case “Appendix L.” Asset management and investment planning has worked on better analysis and prioritization methods and tools that include reliability, safety, finance and regulatory considerations. IUSA has also used consultants to try to establish such a tool. Establishing an appropriate analysis and prioritization tool has been an important engineering goal that thus far has not been achieved. Engineering management says that the analysis and prioritization tool, which was a high priority item, has been pushed to the back burner due to problems with capital spending.

For the 2012 capital budget, investment planning asked the capital budget contributors to prioritize their budget projects in three levels. Priority one is high priority that should be completed within the next year. Priority two is medium with recommended completion dates in one to two years. Priority three is lower and would be required after 2013. Not all of the capital budget contributors provided prioritizations from a bottom-up basis for 2012, according to the Company.

For 2012, a number of multi-year projects that would not be completed in 2011 as planned were “carryovers” into the budget year. These projects are the first priority and represent about 18 percent of the 2012 capital budget, but caused obvious problems in funding new required projects in the budget year. In fact, the new projects requested in category one, or the highest priority, was greater than the remaining target capital expenditures. In light of this, network investments (T&D capital expenditures) were prioritized next. Fleet, generation, general services and IT were allowed only their most important projects; a specific dollar amount was allocated to each of these groups. In one case, an important system planning project was included while at the same time putting a carryover project on hold. A request for additional capital dollars prepared by investment planning above the “Appendix L” levels was rejected by the Board.

Unexpected carryover projects have caused problems in funding new projects and ongoing programs for 2012. Liberty believes that prioritization from the bottom-up into only three categories also causes unnecessary problems in allocating capital dollars. If the projects were rated from first priority to last priority from the bottom-up, higher-level prioritization would be made easier. The recent difficult allocation process confirms that the Companies do not have effective processes for project prioritization and funds allocation at this time.

11. The Company does not have informational feedback loops in place to evaluate the quality of capital project analysis and prioritization efforts. *(Recommendation #1)*

Liberty did not observe organized feedback loops or audits that have the purpose of improving capital project analysis or project prioritization information. The Company noted in its response to related Data Request #1063 that "… projects and programs are included in the capital investment plans based upon cost estimates and expected benefits at the time the plans are being assembled. Once a project or program is in a plan, variances from the plan are examined monthly. That examination helps creates learning opportunities that make future project and program projections better."

Best practice for utilities includes selective auditing or other detailed review of the various assumptions, cost estimates and project impacts on costs or reliability included in the justification of capital projects versus actual results after a period of time following project completion. Several major capital projects and programs should annually be selected for review to learn from previous experience and to evaluate the effectiveness of cost and benefit estimating methods. Liberty concludes that such activities are not currently in place at IUSA.

D. Recommendations

1. Complete a major overhaul of capital budgeting processes and activities, in order to produce a more structured, realistic, and supported approach to capital budget development and monitoring. *(Conclusions #1, #2, #3, #10 and #11)*

IUSA needs to take comprehensive and immediate corrective action to improve the planning, design, cost estimating and execution of capital expenditure budgets. Weaknesses in its current methods have routinely been producing "catch-up" spending programs that engender inefficiency. IUSA has made changes recently to produce improvements in what has represented an area of significant weakness. IUSA has, for example, formed asset management and investment planning functions to enhance infrastructure management and spending discipline. However, significant gaps remain in key processes and results. Many projects remain in an unrefined state when incorporated into budgets; spending rates versus monthly budgets continue to be unmet; and projects scheduled for completion in the current year continue to carry over to the next year too frequently. Factors such as these offer strong indicators of inefficiencies in capital planning and expenditure processes.

The enhancements required need to focus particularly on the following weaknesses in current practices, with further explanation of some following in subsequent paragraphs:

- Projects too frequently come before executive management and the Boards for budget approval before a refined design (*e.g.*, technical specifications, and site and equipment details) has reached a stage that supports meaningful cost estimates; this impedes meaningful budget formation and monitoring of progress).
- Projects are subject to substantial additional design and re-estimates after they have been approved by senior management and the Boards, causing significant project delays.
- Monthly cash flow estimates routinely get missed by significant margins; concerns about how sound budgets are in the first place make it difficult for senior management and the Boards to examine variance causes meaningfully.
- The first-year costs of multi-year projects appear in budgets approved and monitored by senior management and the Boards, but without visibility on what subsequent-year costs

will be by month; this undermines the oversight role of the Boards and the ability to monitor progress against total project estimates.

- The lack of a backlog of "ready" projects promotes inefficiency when delays occur and minimum annual spend requirements exist.
- The lack of a more rigorous and action-oriented review of individual projects varying by more than preset amounts (*e.g.*, +/-10%) diminishes assurance that the causes of variances will be effectively examined and addressed.
- Engineering, design, and estimating of major infrastructure projects needs to be advanced substantially to support inclusion of meaningful detail into five-year and ten-year Capital Plans.
- The target acceptable capital budget variance for each business unit (NYSEG and RG&E electric and gas) should be five percent or less. Such targets currently do not exist.

The engineering, design, and cost estimating subset of the total process comprise the root cause of most of the capital expenditure process problems. Liberty recommends that this part of the process be completely re-engineered.

Liberty also recommends that new analysis and prioritization tools and processes be implemented. The following are the results that are expected due to implementation:

- All capital expenditure projects and programs of $1 million or more should be consistently analyzed with new models that that use economic, system planning, reliability and safety criteria.
- All items included in the bottom-up capital expenditures budgets should be ranked from one to 25, (or the number of projects included) by the originating department and by Investment Planning. (not Priority Categories 1, 2 and 3, as is currently the case.)
- Investment Planning should implement a process for prioritization between the CAPEX-proposing functions that performs an overall prioritization by the analysis criteria.
- Further develop processes for proposing non-"Appendix L" projects included in the capital budget to the NYPSC, as well as providing much clearer information to the Boards.

Another need is to establish formal informational feedback loops for project analysis and project prioritization. IUSA should establish a functioning evaluation and feedback process for completed capital projects. The feedback loop would compare the assumptions and quantitative estimates that were used to justify the project with actual results. A formal feedback loop of this type has two objectives: (a) to improve information and assumptions used in project analysis through "lessons learned," and (b) to provide accountability regarding the information used to justify projects. A second and similar feedback loop should be established on annual capital budget prioritizations to provide immediate feedback and to improve the capital allocation decisions.

2. Develop five-year and ten-year IUSA strategic plans and strongly link with rate plan forecasts and annual budgets. *(Conclusion #8, Chapter XIV Recommendation #1)*

The benefits of establishing a long-term strategic plan, such as the "informal" ten-year analysis established by IUSA Corporate Planning, is that it provides a long-term view and infrastructure touchstone for the Boards, executives, the NYPSC and other stakeholders. A long-term plan with specific goals, objectives and targeted areas of infrastructure investment can be used to determine the long-term affordability or finance-ability of infrastructure plans. It also provides the framework for shorter-term planning. Liberty recommends that a strong linkage be developed between the newer five and ten-year plans and the Company's rate case and budgeting processes.

The long-term strategic plan must first have the general consensus of the NYPSC and other major stakeholders. It would provide a touchstone and roadmap for preparing the medium-range and annual plans required to reach infrastructure and reliability investment goals. The Company's five-year capital forecasts, three-year forecasted rate case filings, and each one-year budget should be developed to demonstrate significant and measurable progress toward meeting longer-term electric and gas system objectives. These plans must be linked to the longer-term strategic plans to ensure that required investments are made, and that budgets and rate plans serve to support the systematic improvement of Company infrastructure.

For example, the recently developed five-year capital plan must demonstrate strong linkage to a strategic ten-year plan, with specific investments that show progress toward meeting the long-term investment objectives. This linkage and systematic progress toward the long-term goals should be demonstrated to the Board and also be shared with the NYPSC. The five-year capital plans form the basis for rate plans, and must also demonstrate linkage to and progress toward the long-term objectives. Rate plans should be strongly linked to the five-year capital plan.

From an annual budgeting perspective, linkage to and progress toward the long-term investment goals and objectives should be clearly demonstrated to company executives and to the Board prior to the approval of one-year capital budgets.

3. Enhance the IUSA Board's role in overseeing capital budget formation and monitoring. *(Conclusion #4)*

The review, approval, and oversight of the capital expenditures budget form one of the most important sets of responsibilities of a Board of directors. The IUSA Board needs to increase its focus on this crucial area, which has been very problematic at the New York Utilities. Particularly given the substantial capital-spending requirements imposed on the Utilities, the Board must be active in assuring not only that spending occurs at required levels, but that all the money being spent is being spent effectively.

Poor performance in executing the capital expenditures budget, as approved by the IUSA and Company Boards, has not emerged suddenly at the end of the year. Liberty's review of the data and discussion with managers demonstrates that adverse trends were clear and had become alarming by mid-year in both 2010 and 2011. The Utilities were clearly making progress at rates substantially less than required to meet expenditure and schedule targets.

The Board requires structural and procedural changes to perform its capital-expenditure oversight role effectively. It should create an infrastructure-focused committee to lead in this area. That committee should become engaged directly and actively in identifying and implementing the changes required to meet the preceding recommendation. The proposed committee should also prepare and recommend to the full Board a structured set of formal reports that will routinely inform the full Board about:

- Linkage between long-range plans and currently approved capital budgets
- The depth of information underlying projects proposed for budget inclusion
- Project- and program-specific variances as the year progresses
- Analysis by management of the causes of variances and actions proposed to address them
- Effectiveness of actions taken
- Assessment of needs for budget and performance improvement on a routine basis.

Program and Project Planning and Management – Electric

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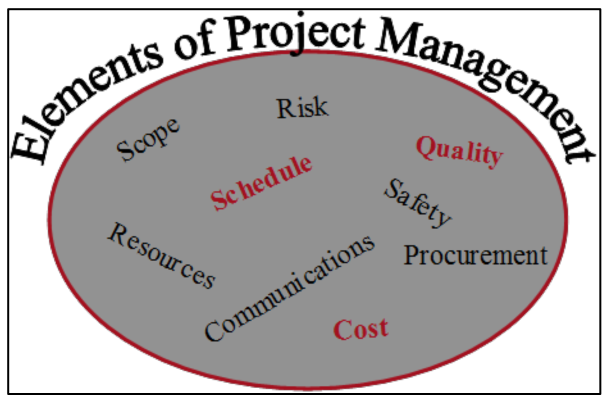
XI. Program and Project Planning and Management

A. Background

Firms requiring large investments in plant, like utilities, by necessity have developed their own approaches to project management. While some projects can at times lend themselves to "turn-key" efforts by contractors, they are the exception, not the rule. Project management is too important for the typical utility to delegate; therefore large utilities all have dedicated programs of project management, although they are of varying approach, sophistication and quality.

The fundamental notion behind project management in a utility is the coordination and management of multiple organizations for the completion of significant cross-functional endeavors. The test then for applying project management concepts is not accounting (capital versus O&M), nor size (large versus small), nor criticality, nor terminology (project versus program), although each has an important role. The critical test is the degree to which it is impractical to manage the overall challenge within the confines of a single organization, or "silo." The necessity to manage work that spans numerous organizations requires a cross-functional approach, and that forms the foundation for project management.

Project management programs come in many variations, but should all include a number of standard components to meet key requirements. The diagram illustrates them. An effective program will contain all of these elements and perhaps more, but three will always emerge as the bottom line objectives: cost, schedule and quality. In fact, it is the balancing of these three parameters that represents the real challenge and skill of project managers.



In addition to evaluating the overall project management elements at Iberdrola USA, Liberty has been directed to examine in particular detail the vegetation management, energy efficiency and Smart Grid program functions.

B. Evaluation Criteria

The evaluation criteria utilized by Liberty for this Chapter are defined in the approved audit work plan and are listed below.

1. Program and Project Planning and Management

A project management program should be in place that addresses all of the elements of project management and is targeted at appropriate cross-functional projects.

A team of project managers should exist that have experience in all elements of project management and have suitable credibility within the necessary work processes.

Large projects should be provided with dedicated support resources, including planning, scheduling and cost engineering skills.

The role and responsibility of the project manager should be clearly defined and understood throughout the organization.

Expectations for project managers should be consistent with the authority and resources given the project manager.

Project management requirements for project participants should be generally consistent across all projects.

Project management principles should also be applied to significant O&M efforts requiring cross-functional participation.

The philosophies, principles and methods of cost management that are described in further detail under "Work Management" should be applied in the project environment. This includes the holistic approach, appropriate systems, measures, analysis, reports and corrective action requirements.

Major components of the work should have their own tailored "cost management plan" that describes the baseline cost, who is accountable and how costs will be managed. Such plans should include the specific actions required of the cost manager and the supporting cost engineer.

Formal approval and kick-off of projects should not be permitted in the absence of reasonably firm scope definition and a cost estimate whose quality is consistent with the current design status.

Large projects should contain "exit ramps" early in the job to permit management re-consideration if costs begin to escalate.

A program of scope control should be in place that identifies scope deviations early, requires analysis of such deviations and the mandatory specification of alternates to mitigate the effects of the deviation.

The construction program should have provisions for the collective management of small projects, as opposed to the standard project management approach.

The project management program should apply to all organizations participating in a project, whether internal or contractors.

The role of quality and its relationship to cost and schedule achievement should be clearly defined and understood by all project participants.

There should be a clear linkage between project management and the budgeting systems, characterized by input from and feedback to those systems.

The relative priority of projects and programs should be defined in the planning and budgeting process and, once projects have been approved, assigned and scheduled, those priorities should be moot (i.e., the project manager should not have to compete for resources).

A process for the handling of contingencies should be defined and the "owner" of budgeted contingency funds for purposes of funding approvals should be identified.

Project management principles that define requirements for contractor project management programs on "turn-key" projects should be in force.

2. Vegetation Management Program

A documented process should be in place for the selection and award of contracts for the vegetation management program.

Contracts utilized for the vegetation management program's physical work should include provisions that facilitate the utility's management of the work.

Performance of various contractors should be compared regularly with the results used to minimize program costs on a continuing basis.

An adequate number of trained utility supervisors /contract managers should be assigned to the oversight of contractors.

There should be adequate oversight and audit of contractor management and payments.

Similar measures should exist for internally performed vegetation management activities.

3. Energy Efficiency Program

A documented process should be in place for the selection and award of contracts for the energy efficiency programs.

All energy efficiency programs should have a Project Manager and a documented PM process in place controlling costs, schedules and quality.

There should be adequate oversight and audit of energy efficiency field operations, including contractor management, customer installations, payments and rebates.

Energy efficiency program goal tracking and reporting should be accurate, consistent and auditable.

4. Smart Grid Program

RG&E and NYSEG should clearly assign responsibility for assessing industry and governmental (particularly DOE and NIST) developments in Smart Grid development and for assessing current network capabilities and potential improvement plans in light of those developments.

The utilities should work actively with other state electricity distribution utilities and the Commission to address issues of deployment, standards, equipment, services, and cost recovery as they affect all New York providers commonly and their operations specifically.

RG&E and NYSEG should have an analytically sound and structured process for examining \the costs and benefits in a comprehensive and quantitative manner of network improvements, in order to be prepared to respond promptly and effectively to increased capabilities, emerging standards, regulatory programs and requirements, and customer expectations.

RG&E and NYSEG should take a proactive role in examining the availability of funding support for network enhancements, and should aggressively pursue opportunities that will have demonstrable benefits for customers at effective cost.

C. Program and Project Planning and Management

1. Background

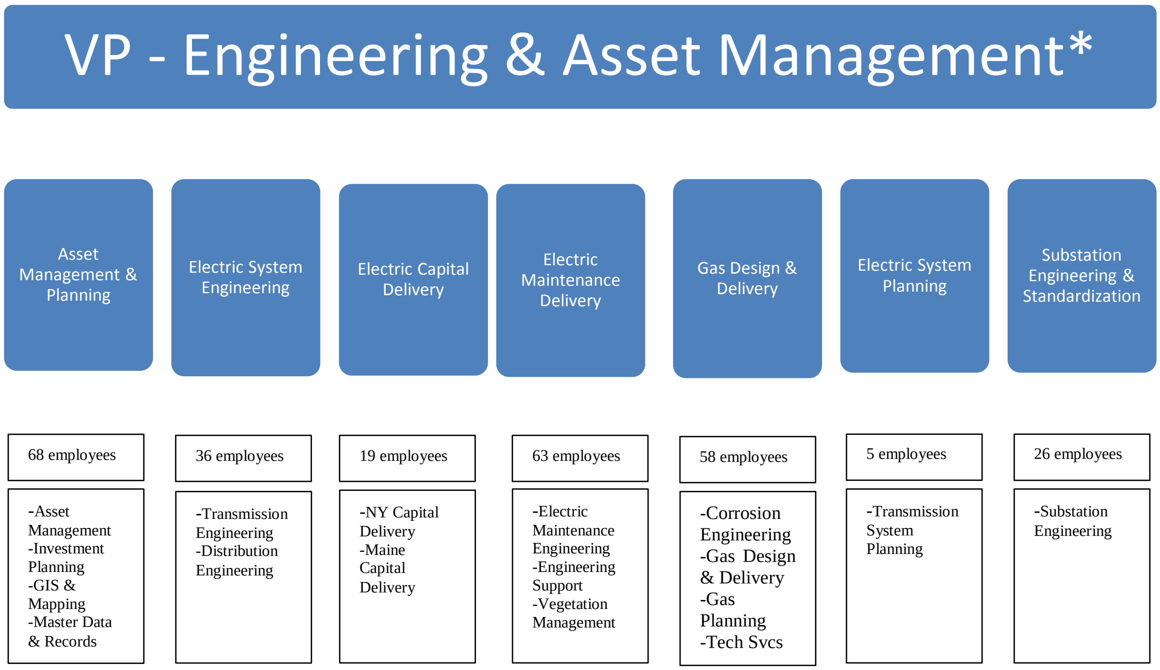
a. Organizational History

Prior to 2009 Utility Shared Services provided back office services (IT, HR, Purchasing, Finance, and Accounting) to the then Energy East utility affiliates using a matrix management approach. The front office operations were structured at the local level with little coordination. Energy East Management Corp. provided corporate and financial services to all affiliates. By December 2009 a new management team was put into place. Utility Shared Services and Energy East Management Corporation merged into Iberdrola USA Management Corporation (IUMC).

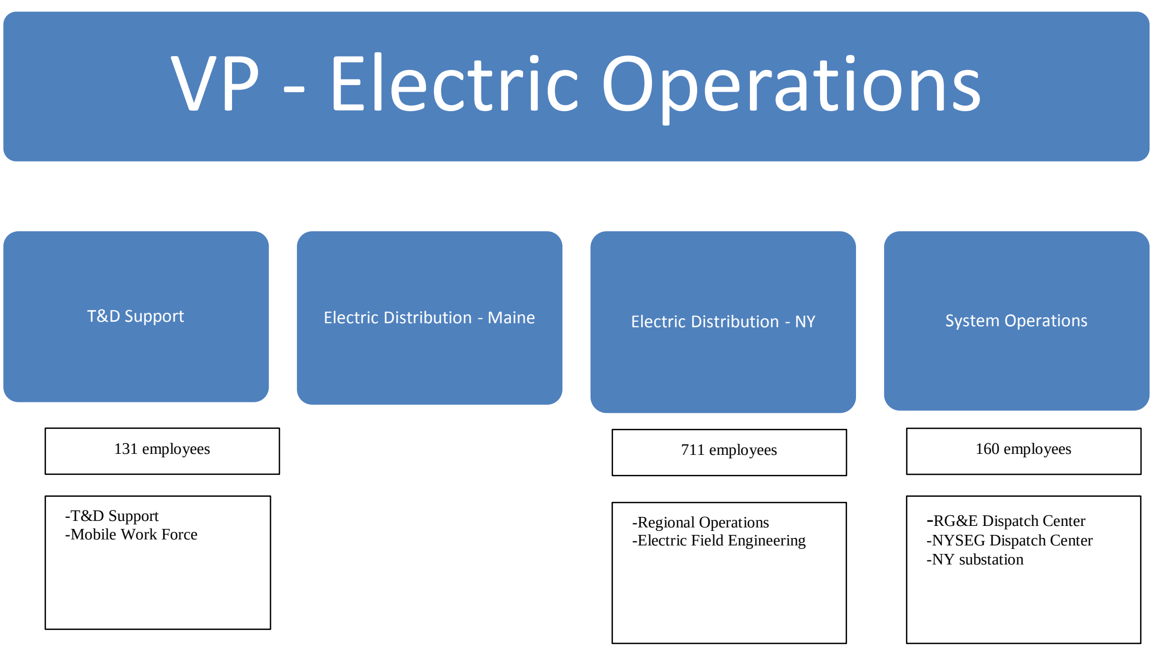
IUMCs scope of services expanded to include an operations focus. All of the assets (personnel, facilities, and equipment) are substantially located in the operating companies. The operating functions are substantially located in IUMC. The matrix structure manages the assets.

b. Electric Organization

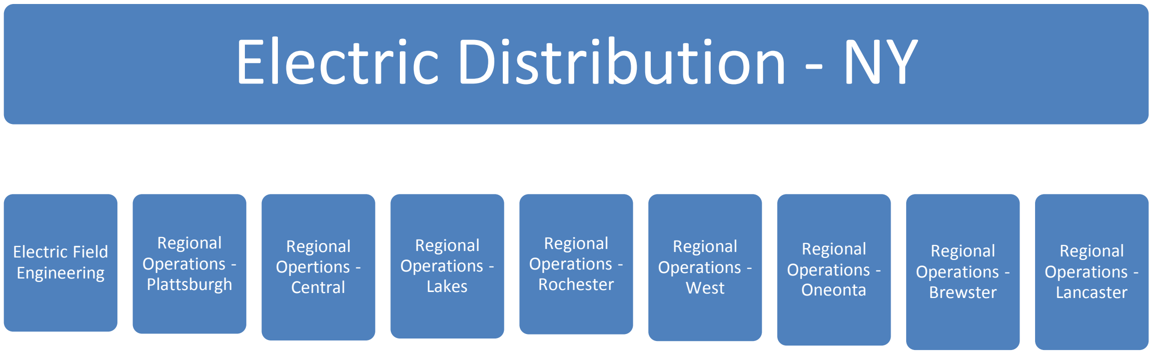
The electric organization in place (as of July 24, 2011) responsible for project planning and management is primarily contained in two departments, Engineering & Asset Management and Electric Operations. These groups function in a matrix organization. The functions in IUMC manage the assets located in the operating companies. Organization charts for the two departments are shown below.



*In July 2011 this department was reorganized. It was split into two departments. There is now a VP-Asset Management & Planning and a VP-Engineering & Delivery.



The Electric Distribution-NY department is further organized into a regional network. This organization is shown below.

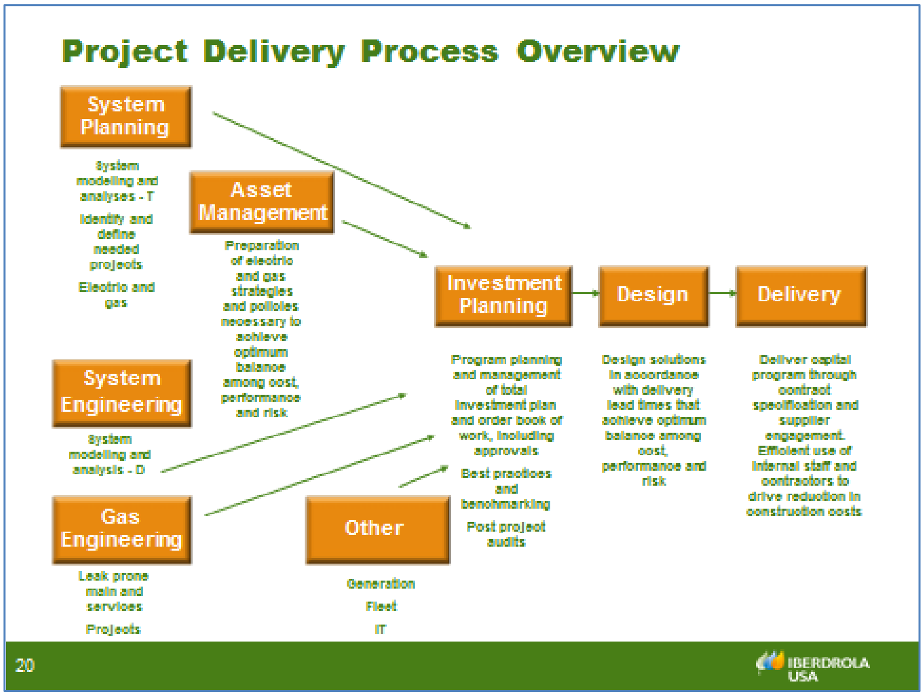


2. Findings

a. Overview of Project Management Process

i. General

The chart below illustrates the overall project delivery process. The Asset Management and Planning group combines the two functions in the chart shown as Asset Management and Investment Planning. This group receives the project plans and budget estimates from all groups in the company. A project is defined as costing $1M or more. They then prioritize the projects and place them in the corporate capital budget plan. A PBAF form (Post Budget Authorization Form) is approved by management to initiate the project and open up a charging account. At that point project managers can start expenditures on detailed design and construction. The Electric Capital Delivery group manages the overall project to completion. This could include the management of design contractors, construction contractors, right-of-way acquisition and internal work force personnel. If the project costs are anticipated to exceed 110 percent of the budget amount, a revised PBAF form must be submitted for management approval.



ii. Project Origination and Prioritization

The substation, transmission and distribution projects originate from several areas. These areas are:

- System Planning
- Electric System Engineering
- Electric Operations
- TDIRP (Transmission/Distribution Infrastructure Replacement Program) Team.

The System Planning department performs long range system planning studies to determine system needs and the best solution to meet them. Once all of the system needs projects have been identified, they are ranked according to three main metrics for comparison and prioritization. The three metrics used are:

- MW Load at Risk – The MW load at risk is determined by identifying the substation(s) that are affected by the given critical contingency and quantify the amount of load that is supplied from the circuits out of affected substation(s).
- Number of Customers at Risk – The number of customers at risk is determined by again identifying the substation(s) that are affected by the critical contingency and quantifying the number of customers that are supplied from the affected substation(s).
- Hours of Exposure – The hours of exposure are calculated by analyzing a load duration curve for the study area. The hours of exposure are determined by identifying the critical load level at which there is a problem and then using the load duration curve to calculate the number of hours that the load level in the study area exceeds the critical load level.

The Electric System Engineering group performs the distribution planning studies. Their planning responsibility starts on the high side of the transformers. They look at the existing loads, load projections, block load additions and other capital projects. They model only the distribution lines seeing load growth rather than on a system-wide basis. The transformer loads are projected out for three years. This process will generate a list of all the system improvement and capacity items. They then rank these items in priority order and forward the list to Asset Management.

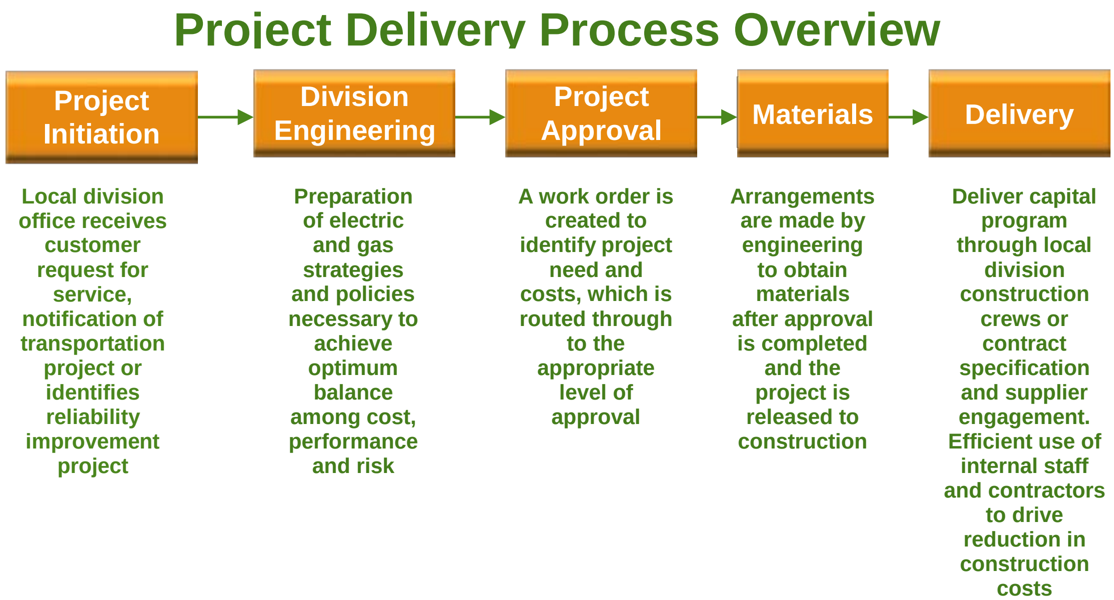
Electric Operations provides budget information on minor capital improvements, meters and transformers. They also furnish information on road relocation projects and large underground projects. This project list also goes to Asset Management.

The TDIRP program is designed to replace substation, transmission, distribution equipment based on age and condition to improve system reliability. The TDIRP budget is a fixed amount for each discipline. Each discipline provides a prioritized project list for their budget based on needs identified by local personnel. Distribution projects are identified and developed by the local Engineering and Operations personnel in the Regions, focusing on the rebuilding of deteriorated infrastructure and/or improving reliability. The project selections are based on operating condition priorities, maintenance history, line and/or equipment obsolescence and maintainability, and required increases in system reliability. Substation Engineering and Transmission Engineering provide project lists of prioritized items for their areas of responsibility.

Asset Management then slots all of the projects in the capital budget based on the overall amount of funds available.

iii. Distribution Project Management Process

The vast majority of distribution capital projects are well below $1M in total cost. For the most part, projects that have distribution work associated with them that are over $1M in total cost are accounted for in a substation project that encompasses the majority of the spending on that given project. The project management process for distribution projects is different from the general process. The overall project management process for distribution electrical capital projects is outlined in the Project Delivery Process overview diagram below.



Distribution projects are currently managed through the local division office staff. Projects greater than $75,000 in capital value are given to the Mobile Work Force for construction review. For projects of this size the Mobile Work Force has first right of refusal. The Mobile Work Force management group will determine whether to complete the construction with internal labor resources based upon available crew complement and the required completion date, or whether to let Capital Delivery contract the work.

If the project is contracted, the project management function will be performed by Capital Delivery. Operations has Contingent Workers that act as the contractor liaison. The Contingent Worker will manage the construction schedules and follow the progress of the crews.

The Capital Delivery group is currently evaluating the use of a program management model to provide for more detailed project management functionality with these smaller distribution projects. A process is anticipated to be in place for 2012.

iv. Contracting Process

The use of design, project management, ROW permitting, and construction contractors is prevalent throughout the project management process. The contractor bid process is defined in the Iberdrola USA Procurement Services Policy Manual. The process is administered by the Strategic Sourcing group. This process applies to all contractors including tree, line, gas and engineering. All material purchases and services over $15k must be a competitive bid. All projects over $100k must be a sealed bid.

Strategic Sourcing receives information on the scope and need for an RFP from the business end. Strategic Sourcing then generates the RFP. They maintain a list of approved suppliers and approved bidder lists. They then allow four weeks for the RFP to be priced by the bidders. Once the bids are in there is a separate commercial evaluation and a technical evaluation of each bid.

For a procurement RFP having a value greater than $1M, the Strategic Sourcing guidelines are to allow 88 working days in the project schedule. The design review time in the schedule can run from 5 to 20 additional working days.

Master design agreements exist with 15 engineering firms. For transmission and distribution construction work there are also master contracts set up with several line contractors. There is no defined set of projects in these agreements. Master agreements have hourly rates for various labor categories. For small projects less than $100k, a normal PO release thru SAP against the hourly rates is done. For projects greater than $100k, the service requirements are re-bid to get a lump sum or fixed price rather than be on the hourly rate.

Construction agreements are normally lump sum bids. This includes substation, transmission and distribution construction. There are some newer unit price construction agreements that are being put into place for transmission and distribution work. Until recently most of the routine transmission and distribution work was done by internal work forces. Contractors were generally used only for underground subway work (duct bank installations).

b. Case Studies

Liberty selected a sample of specific projects and programs for a more definitive "case study" approach. The purpose of performing the case studies was to examine how the policies, plans, and procedures produce results. Each case study considered how the various elements of the program contributed, or failed to contribute, to project success. We looked for corrective action opportunities that were taken or missed, and how the project management program facilitated, or should have facilitated, those opportunities.

The criteria for selection of these case studies included:

- The size of the project should be relatively large.
- All key organizations should be represented on the project.
- The project should be considered an important, or at least typical, element of the construction or O&M effort.
- The project should be traceable through our audit elements (e.g., how was its need defined in load forecasting, how did its design emerge from system planning, and how did it get into the budget).

The case studies selected were:

- Corning Valley Substation and associated 115 kV line
- Webster East New 12 kV Source
- 2011 TDIRP (Transmission/Distribution Infrastructure Replacement Program) Projects

i. Corning Valley

aa. Scope of Project

Corning Inc. is adding up to 27 MVA of new load at various facilities around the Corning, NY area. The existing electrical system is capable of adequately supplying the additional load under normal conditions. However, by the summer of 2009, the loss of certain transmission lines would result in sub-marginal conditions in the cities of Elmira and Corning. A $53M project was initiated in 2007 to upgrade the electrical facilities for this new load. This project was in the final stages of completion at the time of this audit.

This project consists of constructing or modifying the following:

- Build a new 230 kV – 115 kV substation (named Stoney Ridge Substation) at a cost of about $14.6M.
- Build a new 9.6-mile overhead 115 kV line from Stoney Ridge Substation to West Erie Avenue Substation. Most of the line segments were single circuit wood structures. Some of the segments were double circuit lines on steel structures. The new line will cost about $14.4M.
- Replace the existing Science Park 34.5 kV – 12.5 kV Substation with a new 115 kV – 12.5 kV substation at Sullivan Park on property provided by Corning, Inc. This work will cost about $16.2M.
- Modify/upgrade portions of four substations (Hillside, West Erie, Hickling and Campbell) to accommodate the new line work. This portion will cost about $5.7M.
- The remaining project funds of $2.4M were for other items such as distribution feeder work, right-of-way acquisition, environmental and licensing, construction management and procurement services.

Overall, this was a major project encompassing many elements and requiring support from many areas of the company. Pictures of some of the facilities that were constructed are shown below.

Typical Wood Transmission Line

Typical Steel Transmission Line

Stoney Ridge Substation

Sullivan Park Substation

bb. Timeline

The need for the project was first identified in 2007. The original in-service milestone was intended to coincide with a customer outage need of May 2011. The customer subsequently changed their cut-over need date to August 6, 2011 and the new substation was energized to be ready for them on July 31, 2011.

cc. Overall Management Structure

This project arose before the Capital Delivery group was formed. The management structure illustrates how projects were managed at that time. The Project Manager (PM) became involved with the Corning Valley (CV) project in late 2007/early 2008. At that time the PM was the Manager of Performance & Budgets in the Engineering Department. This was a five person unit. Corning Valley was the PM's only project.

One of the first actions by the PM was to form a project team. All of the initial members of the team were internal personnel. The PM formed the team by contacting individuals and supervisors to secure a person responsible for a particular project area. A project contact list was developed. An organization chart was not prepared.[1] Some of the key internal positions and areas were:

- Substation Project Engineer – overall lead for substation design. He was assisted by another substation design engineer.
- Substation Protection Engineer – lead for the protection systems
- Transmission Line Engineer – overall lead for transmission line design. The particular engineer assigned to this project was a routing expert.
- Procurement Lead
- Substation Procurement
- Major Equipment (including transformers)
- Real Estate
- Substation and Line Construction Services.

Based on decisions and actions by the internal team, various contractors were then employed on the project. Some of the key contractors were:

- TRC - The detailed engineering for this project was contracted to TRC in early 2009. TRC did the detailed design for the substation, transmission and protective coordination. They also handled the environmental, licensing and construction management.
- DDS - The site preparation and below grade work required at two of the substation sites was awarded to DDS. Four separate Purchase Orders were given to DDS to account for the site prep and below grade work at the two new substation locations.
- Michels Power - The transmission construction and the substation above grade construction packages were awarded to Michels Power.

[1] A project contact list does not clarify reporting relationships as well as an organizational chart.

An internal work group, Mobile Work Force, was engaged to perform some below-grade work at three of the substations. The work scope and schedules were negotiated with the work group. This avoided the need to hire a contractor at those sites. In addition, other internal work groups did the above-grade work on two substations.

dd. Findings

Schedule

This was one of the few projects in NYSEG with a "drop dead date." Most of the project in-service dates are "open." The project was delivered on schedule. The schedule was kept on MS Project software. The contractors had date milestones in their contracts. DDS had an independent schedule and an on-site scheduler. Overall the schedule results were excellent. However, this did come at an increased cost (see Change Order section below).

Budgets

The project was authorized on a UPAF (Universal Project Authorization Form) dated February 14, 2008, in the amount of $50M. Since it was a customer-driven project it was not in the approved spending plan. The project estimate at that time was ballpark due to the many unknowns. It turned out to be fairly accurate. The detailed project estimate done on July 1, 2009, had an estimated cost of $53M. The project is coming in under that figure. Since a revised project approval form is not required unless there is a cost variance of 10 percent or more over budget, the original UPAF was the only one submitted.

Project Coordination

The PM held engineering review meetings every Wednesday. This approach gave them good information for a construction review meeting on Friday. Copies of detailed minutes of the monthly meetings were available and were reviewed.

TRC provided design services and construction management services for this project. TRC provided a Field Supervisor (a retired NYSEG employee) as part of their contract that reported to the PM. This provided the PM with an on-going on-site presence.

Unique Project Challenges

The transmission line construction configurations were single pole, H-frame and also some self-supporting steel poles. There were nine different transmission segments. The State of NY has different permitting regulations depending on the voltage and line length. Lines greater than 69 kV and greater than 10 miles require more up-front PSC involvement than other lines.

The transmission line had the typical right-of-way issues. A mining operation that was crossed caused some unique problems. Some spans were redesigned for extra mining equipment clearances. A small underground section of solid dielectric cable was installed on the Sullivan Park exits. The Stoney Ridge substation site was purchased. The Sullivan Park substation site was on Corning Valley property.

Materials

The substation Project Engineer maintained a material procurement schedule. Engineering also prepared and submitted the specifications and managed the RFP process for large material items, such as the 230 kV transformer at the Stoney Ridge Substation. The material POs included required delivery dates. Transformers were shipped directly shipped to the foundations. Circuit breakers were shipped to the warehouse. Only partial material payments were made if there was any issue.

Contractor Bids and Payments

The construction contracts were lump sum bids with a not to exceed amount. The construction work for each substation was broken down into three contracts – site development package, below grade package and above grade package. However, the detailed estimates were not developed with the same work breakdown structures. This made it impossible to review each individual construction bid to determine its agreement with the estimated price.

The PM initiated payment to the contractors was based on the percent complete for different items. There was a 10 percent retainage that was kept until the end. The only contract penalties for missing dates were in the liquidated portion of the contract.

The design contract was a time and materials contract with a not to exceed amount.

Quality Assurance and Control

The material vendors provided required test results for their products. The above grade contractor, Michel's Power, provided the substation testing. Internal work forces also did some acceptance testing. TRC did transmission line inspections. The Field Supervisor that TRC provided to report to the PM was always on-site and brought up issues to the PM.

Both the high voltage commissioning and other electrical commissioning were separate planned and budgeted tasks in each substation.

Contractor Change Order Process

The change order process for out-of-scope items requires the contractor to submit a Change Order request. The PM had copies of the requests that they approved. They did not have copies of the ones which were denied. Those change orders were simply handed back to the contractor.

When a change order was requested, the PM had an inspector or field supervisor review the scope, verify the need and review the cost estimate. The PM would then approve and forward the order up to Management for approval per the Iberdrola approval guidelines. After approval the Change Order would go to Purchasing. The SAP system Purchase Order (PO) would have the change added so the PO amount in the system is up to date.

The contractor change order percentages are shown in the table below. The total amount of the contracts was $20.5M. The total amount of the changes orders before any adjustments was $4.9M, which was 24 percent. After adjustments were made, the percentage was 18 percent. The volume of changes were high (greater than10 percent). Overall, this level of estimating accuracy is poor.

Work Element	Overall Change Order %	Adjustment for Major Items	Revised Change Order %
Sullivan Park site work	116%	$539,887 of sub-surface conditions	24%
Sullivan Park below grade	36%		36%
Stoney Ridge site work	32%		32%
Stoney Ridge below grade	28%		28%
Above Grade - Stoney & Sullivan	29%	$200,075 for schedule increase, $267,496 for overtime for control house schedule	7%
Transmission line	22%	$852,378 for schedule increase	10%
Design services	31%		31%

A number of the change orders were for schedule accelerations. One large change order for $852,000 was noted. This order involved accelerating the transmission line construction schedule. One section of the line passed an area where bald eagles were nesting. The State put a moratorium on any line construction in that area from February to June of 2011. The substation energizing date was June 31st. This affected the transmission line contractor and required them to change their schedule. The $852,000 was for a two week schedule increase, which reflects a high fee for such a short time. The PM stated it was hard to approve, but was done due to the customer need. Also, the fact that many other change order requests had been denied was a negotiating factor.

The design contract was a lump sum with a not to exceed amount. There were 25 design change orders totally to a 31 percent cost increase over the original bid. Some of the changes of note were:

- $154,955 - The justification was cited as "Out of scope substation and engineering support…due to limited availability of NYSEG substation engineering personnel…"
- $113,550 – "The level of engineering support needed to answer contractor and NYSEG construction forces' questions and deal with material and equipment issues …is far exceeding what was initially expected…"
- $84,960 – "Additional funding will be needed to provide Construction Management Services in support of timely completion of this project."

Contingency Management Process

There was no defined contingency control process or procedures which were followed. The PM tracked the contract change orders and managed them against the overall budget. The detailed estimate from the design contractor had an overall contingency amount of $5,312,000, which was 9.9 percent of the overall budget, including all overheads and adders.

The original construction contractor bids were well under the amounts estimated. This enabled the PM to successfully manage the project costs below budget despite the high change order amounts. The total change order amount of the construction and design contracts was $4,962,289. Overall the construction contracts totaled $20.5M, which is 39 percent of the budget, and accounted for 93 percent of the total budget's contingency fund.

ii. Webster East

aa. Scope of Project

Heavily loaded areas of the Town of Webster that did not benefit from the installation of a 12kV source on the western side of the town were in need of load relief. Two of the 4kV circuits at Station 424 have experienced 400+ amps during summer peak load periods for the past few years. Numerous low voltage complaints in year 2005 had been "fixed" via the installation of voltage regulators and capacitors. However, during the summer of 2006, these remedies proved to be insufficient in providing acceptable voltage on one of the circuits. Residential growth from new subdivisions was still occurring, along with new commercial venues. This project will provide the 12kV source for use in converting the remaining 4 kV circuits to 12 kV, thereby alleviating loading and low voltage problems that have plagued the area for many years, as well as provide the capacity for supplying new load growth. The total cost of this work is estimated to be $6.1M.

This project consists of constructing or modifying the following:

- Expand the existing Station 424 substation to accommodate the installation of a new 34.5-12.5 kV transformer, three 12.5 kV distribution feeder circuit breakers and a new control house. This portion is estimated at $3.1M.
- Establish three new 12.5 kV distribution circuits. These three new circuits will run underground north out of the station in a new conduit system. All three will terminate on existing poles and branch off to feed the existing infrastructure, which will be converted from 4 kV to 12 kV. This portion is estimated at $3M.

This project is currently scheduled for substation construction to restart in January 2012 with an in-service date of June 2012. $2.6M has been spent to date.

Transformer & vacant distribution bays

115 kV support structures

bb. Timeline

This project has experienced some starts and stops. A timeline is shown below. This data was constructed from a number of sources, including UPAFs and data requests.

2006 - Need for project was identified and project was slotted in the approved spending plan.

January 22, 2007 - A design contractor, Hatch Engineering, was hired to complete the detailed substation engineering design.
March 7, 2007 - The original budget authorization form was signed for a total of $2,081,000. Substation accounted for $1,581,000 and distribution portion was estimated at $500,000.
2008 - Substation construction was started. All of the in-ground work has been completed except for the control house foundations and some conduits. Also all of the structures have been installed and the transformer has been purchased and set in place. All of the major equipment has been purchased and received except for the control house.
January 14, 2009 - The project was placed on hold in an austerity freeze. The project's in-service date was deferred. Also the purchase of any equipment not on order was deferred to early 2010.
2010 - New estimates were generated to complete the project. The new substation estimate increased to $2,150,000 (an increase of $570,000). The revised distribution estimate increased to $2,990,000 due to unforeseen load growth in the Webster area, as well as an expansion in conversion area to better facilitate future load and increase circuit reliability. The revised total for the project is $5,140,000, an increase of $3,059,000 from the original authorization.
August 27, 2010 - DDS Utilities, Inc. was issued a construction release order for future Distribution Subway Construction work.
September 24, 2010 - First distribution work package containing the work to install new conduit and cables from the station to the existing poles was issued to DDS Utilities, Inc.
October 27, 2010 - Substation Engineering Co. (SECo) retained for Substation Detailed Engineering and Design Services to reevaluate the engineering and to restart the substation engineering portion of the project.
October 30, 2010 - DDS completed installation of the first distribution work package.
November 19, 2010 - A distribution work package to install new conduit and cable to accommodate the conversion work was issued to Liberty Underground, Inc.
January 7, 2011 - An updated and corrected substation engineering Conceptual Package was issued by SECo to RG&E for review.
March 14, 2011 - A UPAF was approved for the unspent dollars in 2010 to be carried over to 2011 to complete the project. The primary reason for the underspend was the availability of contracted resources for engineering and construction. The overall cost of the project has not increased from $5,140,000. The cost to complete the project in 2011 is $3,103,000. Engineering was anticipated to be completed in 2010. Construction was anticipated to be completed by 6/30/2011.
March 21, 2011 – Distribution work package that was issued on 11/19/10 to Liberty Underground is completed.
March 31, 2011 - SECo was issued a PO for this project for Project Support Lead Services.
May 16, 2011 – RG&E retained the services of SNC Lavalin to provide Owner's Engineer services. SNC provided comments on the Conceptual Package to SECo.
July 7, 2011 - Procurement department issued the control house bid package for bid to five bidders.
July 18, 2011 - An updated project cost and cash flow for 2011 and 2012 was issued. This includes $2,790,000 for distribution and $1,101,000 for substation for an overall remaining project cost of $3,891,000. This does not include costs already spent prior to 1/1/2011. The estimated in-service date is June 2012.
July 28, 2011 – Only one of the five manufacturers invited to bid provided a bid on the control house.

Current Distribution Status (October 1, 2011):
The second subway work package is in the process of being issued to DDS Utilities, Inc. to install new conduit on Webster Road. This work is anticipated to be completed by 10/1/11.

Subsequent packages (8 total) encompassing the overhead pole work and the cable work were issued during the last quarter of 2010. RG&E's overhead line crews have not progressed the work as anticipated. As a result, the overhead work will be bid out to contractors. RG&E Operations is currently in the process of obtaining contractor resources for this work.

Current Substation Status (May, 2011):
The Project Manager was going to go with the single bid on the control house rather than rebid so that construction could proceed. Other anticipated actions are:

- Award Control House/Relay Panels - August 31, 2011
- Bid package out for Substation Construction - November 1, 2011
- Restart substation construction - early January, 2012

cc. Overall Management Structure

The management structure of this project has been in transition from the prior project management process to the present day practices. The three UPAF budget forms had a different person listed for the project manager each time. Each of these persons was an engineer in substation engineering. At that time, for a small substation project such as Webster East, the substation engineer was the assigned project manager.

In 2010, when Capital Delivery was formed, the project was assigned to one of their project managers. Webster East was one of about 40 projects assigned to them. Due to priorities on the other projects they never advanced the Webster East project to any extent.

The PM work is now handled by a SECo contractor. There is no organizational chart. Some of the key positions and areas are:

- Capital Delivery PM – Functions as an internal contact only.
- Project Manager - SECo Project Support Lead - Substation Engineer. This person functions in the traditional PM role. Former RG&E employee.
- Owner's Engineer - SNC Lavalin employee
- Substation Engineering – RG&E employee
- Substation Designer – SECo employee. Former RG&E employee.
- Substation Protection Engineer – SECo employee. Former RG&E employee.
- Distribution Engineer – RG&E employee
- Procurement – RG&E employee
- Real Estate – RG&E employee
- Construction General Foreman – RG&E employee
- Distribution Subway Contractor - DDS Utilities, Inc.
- Distribution Subway Contractor - Liberty Underground, Inc.
- Distribution Overhead Contractor - O'Connell Electric

dd. Findings

Management Structure

This project illustrates the state of flux the project management program has been in since Capital Delivery was formed. The initial number of project management resources in Capital Delivery was not sufficient to meet the demand. The Owner's Engineer brought on board in May 2011 is now a part of the management structure. The roles in this new management structure are not yet defined. A general description of the roles is shown below. Note that this includes design, engineering or management functions only. The actual contractors that do the physical work are not listed below.

- Capital Delivery Project Manager – They function as the internal contact only. They do not appear to be involved in the daily project management details.
- Project Manager – This is one of the Owner's Engineer employees. They function in the traditional project manager role.
- Owner's Engineer – They will represent the owner. One function will be to prepare the substation RFPs for materials and coordinate this with Procurement.
- Transmission Engineering Internal Contact - They function as the internal contact. They use contractor design information to estimate the project. They assist with transmission material procurement issues.
- Transmission Engineering Design Contractor – Prepares detailed location and designs. The may do environmental, licensing and field construction management activities.
- Distribution Engineer – They prepare and manage all of the distribution engineering functions.
- Substation Engineering Internal Contact - They function as the internal contact only.
- Substation Engineer – This role will be contracted. They will function as the substation Project Engineer. The functions include attending meetings, overall design reviews and making major decisions.
    - Preliminary Substation Contractor – This role will be added if needed. They will prepare conceptual designs.
- Substation Designer – This role will be contracted. They will review design details including reviews and approvals of detailed drawings.
    - Substation Final Design Contractor - This role will be added if needed. They will prepare the detailed designs.
- Substation Protection & Control Engineer - This role will be contracted. The functions include attending meetings, overall design reviews and making major decisions.
- Substation Protection & Control Designer - This role will be contracted. They will review design details including reviews and approvals of detailed drawings.

The functions of these roles, responsibilities and the process flow between these roles have not yet been determined. Lines of responsibility are unclear.

The Webster East roles are a part-time project for the Project Managers. The internal Capital Delivery Project Manager contact (who was new to their position) has eight assigned projects. Four of their eight projects also have a contracted project manager and four do not. The SECo project manager for Webster East has six total active projects with Iberdrola.

Schedule

After 2008 – 2009 program freezes, the substation construction was restarted. Since the restart, the June 2011 in-service date has been moved to June 2012.

Budget

At the time of the construction restart the cost was re-estimated and increased by over $3M.

Estimates

The latest detailed estimates were reviewed. The distribution estimate was for $2.99M, which is the total estimated cost of the distribution work. The substation estimate was for $1.4M, which is the cost of the remaining work to be completed.

The distribution estimate was a crude ballpark estimate created outside of SAP. It has breakdowns for materials, labor, etc. as necessary for the budget approval forms. Other than that there were no work breakdown structures that could be used for project management functions. The contingencies used were $10,000 which is less than ½ percent.

The substation estimate was prepared outside of the Substation Estimating System. It was a detailed estimate. Major equipment costs were identified with material and labor breakdowns. Contractor work was also broken down. The contingencies used were 19 percent.

Distribution Work Processes

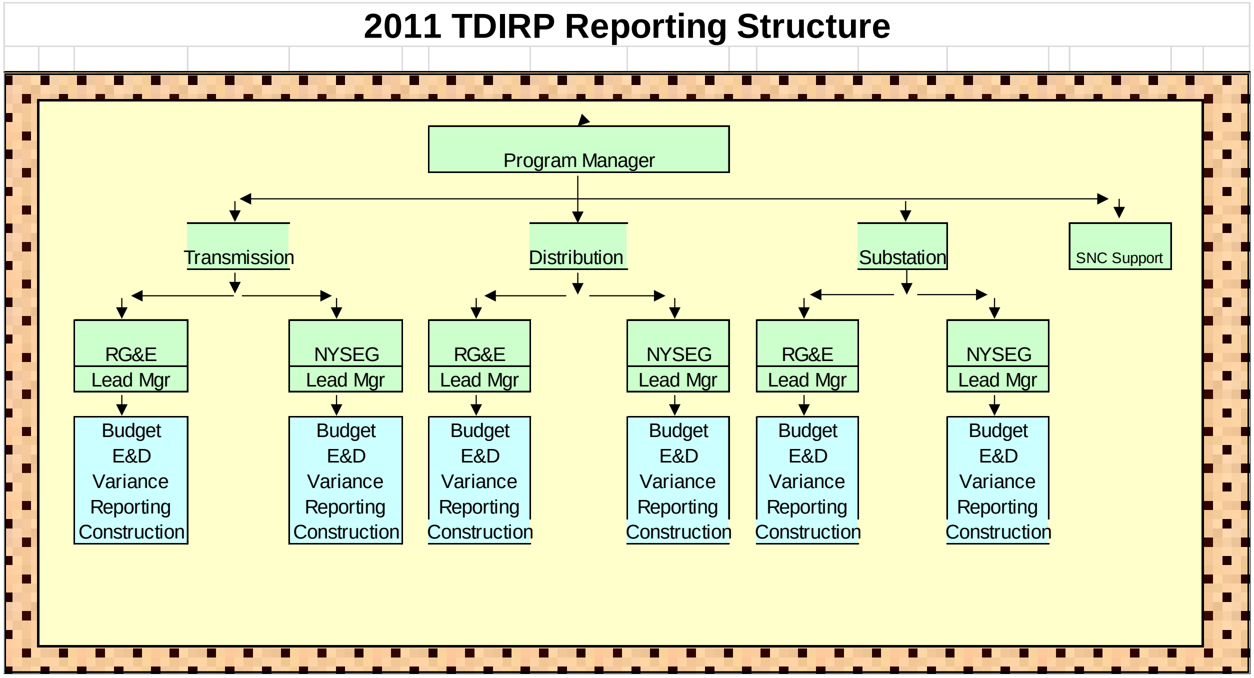
The distribution voltage conversion work packages were issued during the last quarter of 2010 to Regional Operations for construction. After being held for over half a year, they are now being returned so they can be worked by a contractor. RG&E does not have any unit price contractors available for work overload. The work was packaged and bid out under the RFP process.

Webster East was unique due to the timing of the job. Operations had a lot of retirements and there are now fewer people to do the work. As a result the work orders were held in the field and could not be completed. They were later returned to Capital Delivery for packaging and bidding out to contractors. It is a new process for RG&E to use overhead contractors to get the line work done. Some of the new processes they are getting involved in with the overhead line contractors are safety issues, such as interactions with the ECC on circuit work notifications.

iii. 2011 TDIRP Projects

aa. Overview of TDIRP Program

The TDIRP program (Transmission/Distribution Infrastructure Replacement Program) has been in place since 2005. The purpose of the program is to replace substation, transmission, distribution equipment based on age and condition to improve system reliability. The project management organizational structure is shown below. The Program Manager is a Project Manager in Capital Delivery. Team member responsibilities in the Regions are defined based on respective disciplines (i.e., Transmission, Distribution, and Substation projects). Team member tasks include project management, variance analysis and reporting, and E&D (Engineering & Design) and construction support. SNC, the Owner’s Engineer, was recently contracted to support the various TDIRP project requirements including management activities, conceptual engineering, detailed E&D reviews, and construction support.



The substation projects consist of major equipment replacements, including power transformers, circuit breakers, instrument transformers, disconnect switches, insulators, relay equipment, and surge arresters.

The transmission projects consist of 34.5kV and 46kV re-builds, pole replacements, cable replacements, upgrades to system based on Region line inspections, and clearance fixes per issues identified by vegetation management surveys.

The distribution projects consist of underground cable replacements, recloser additions and replacements, arc-series street lighting conversions, pole and wire replacements, and cable lead upgrades.

These projects are in various stages ranging from conceptual engineering to final construction.

Company	Discipline	Targets (000s)	2011 (000s)
RGE	Substation	$ 5,000	$ 5,000
	Transmission	$ 5,000	$ 2,500
	Distribution	$ 5,000	$ 7,500
NYSEG	Substation	$ 15,000	$ 9,000
	Transmission	$ 5,000	$ 3,000
	Distribution	$ 5,000	$ 13,000
		$ 40,000	$ 40,000

The overall 2011 TDIRP budget is $40M. The normal division of these funds by the Program Manager is shown in the table in the Targets column. This target discipline split is a starting point, and is not firm. It is based on historical rates. The Program Manager can move funds between the disciplines but not between the two operating companies. The 2011 budget reflects a movement of funds to provide for more distribution construction work in both companies. During the year, depending on how schedules are proceeding, the Program Manager could move funds between the disciplines as needed. A $500,000 contingency fund is maintained to cover emergencies.

The distribution portion is then further divided among the regions. In 2006 a percentage assignment was determined based on number of customers and age of plant. Except for some minor tweaking in 2008 this percentage has remained basically unchanged. During the year, funds are not moved between the regions. If a project is delayed, the regions will use their funds on other region projects.

bb. Setting Program Priorities

Distribution projects are identified and developed by the local Engineering and Operations personnel in the Regions, focusing on the rebuilding of deteriorated infrastructure or improving reliability. The project selections are based on operating condition priorities, maintenance history, line and/or equipment obsolescence and maintainability, and required increases in system reliability.

Each region decides their distribution project priorities. A carryover project is high priority. Some of the carryovers could be solely due to materials being ordered, not because the project was under actual construction. Projects were prioritized based upon circuits identified as Worst Performing Circuits, line segments with high customer counts, poles that were deteriorated or line segments with inadequate conductor sizes. Frequently, line segments are rebuilt within new easements along roadways to further enhance reliability and accessibility. There are some general TDIRP program guidelines provided for guidance in assigning priorities. For instance, old conductors being replaced should have over X number of customers on them. The final decision for the priorities is left to the Regions. The 2011 NYSEG distribution project list contains over 500 individual projects.

Substation Maintenance provides recommendations on other substation equipment. Transmission Engineering provides recommendations on the transmission items. The TDIRP Program Manager ends up with a prioritized item list from the three disciplines separated by companies.

One new area of priority input is now coming from Asset Management. The Asset Management Team (composed of 9 people) will look at the asset condition inputs, develop a health index and then develop a recommendation plan for asset maintenance. The general process is to first perform a condition assessment and then perform a risk assessment. The combination of this data would yield a health index. The condition inputs come from the reliability reports, failure rates, inspections, etc. Based on risks an asset management strategy is then developed. This process will eventually be used for a 100 types of electric and gas assets. The first assets being done are circuit breakers, distribution poles, and substation batteries. Once the assets with a poor health index are identified and listed, the lists are used by the respective disciplines in formulating their priority plans.

cc. Program Management

Distribution designs are routed through management approval prior to being released for construction. Projects are approved by Engineering Managers and Supervisors and Operations Managers. Each individual work order is approved. less than $20k approved by Field Engineering Supervisor, $20 - $50k approved by Field Engineering Manager, $50k -$200k approved by Director and greater than $200k approved by Vice President.

The Program Manager monitors activity in each of the disciplines. All the projects are loaded into SAP with a rollup structure. There is one line variance per discipline per company on the report. The Program Manager meets with the TDIRP team bi-weekly to look at budget actuals. If one project in the region will be delayed, the region can use those funds on some of their other projects. They often have unspent funds coming in from substation or transmission that can cover additional Regional distribution work. A monthly report is prepared for the Major Projects Executive Steering Committee.

SAP reports are cumbersome to use for managing the distribution program. SAP requires a lot of data dumping and manual manipulation to get reports on a series of work orders. A simple report listing the NYSEG TDIRP project list with construction expenditures on each project to date took more than 16 engineering hours to create.

There are no written expectations or schedules during the year for each individual project. The unwritten expectation is that all work is completed by the end of budget year or it is carried over. During the year Field Engineering will have verbal discussions with Operations on any jobs that are critical. They share the same reliability goals with Operations. The availability of outside resources is a consideration in whether a job can be completed.

The individual project manager could come from a number of sources, depending on whether the project is substation, transmission or distribution. The size of the project is also a factor. Starting in 2011 SNC, the Owner's Engineer, will provide some management services for TDIRP. These services will include preliminary engineering, detailed engineering, engineering construction support, interface with construction operations, budget tracking and reporting.

dd. Findings

Project Priority Setting

The TDIRP program is one of the few that has survived through numerous reorganizations and management changes. The involvement of local personnel and local knowledge in each discipline area in setting priorities is one of the reasons for its success. Each discipline area has a fixed budget that does not need to compete with other programs. Overall the priority setting process functions well for directing expenditures to the area of need.

Project Management Issues

The workload in the Capital Delivery area has affected the advancement of the projects. Much of the 2011 work consists of 2010 carryover projects. Over $15M of substation and transmission projects were carried over. Not all of these carryover projects are due to project management delays. Some of the projects could be carried over due to equipment being on order.

The SAP enterprise management system has obvious shortcomings in managing a group of projects. It is not able to provide program work management by aggregating a list of individual projects. Project report lists are only prepared in extreme cases due to the effort involved. As a normal work management tool, SAP is not able to produce effective reports. Resource management is not possible. The main source of progress information from SAP flowing to the Program Manager is financial budget data (actual expenditures to date) based on the project work orders that have closed.

c. Findings

i. Project Management Program

A project management program should address all of the elements of project management and be targeted at appropriate cross-functional projects.

The Electric Capital Delivery work group has been set up for the project management function. The NY section of this work group consists of:

- Seven Project Manager Positions: These positions perform the traditional project manager role for all projects large enough to require this function. This is their sole task.
- One Supervisor Construction Position: This position functions as an internal construction advisor for the project managers.
- Two Lead Analysts Positions: These positions assist the project managers in the analyst role. One is proficient in the use of MS Projects scheduling software.
- One Clerk Position: This position enters the substation work orders into the SAP enterprise management system.

More detailed information on the team of project managers is located in section ii. directly below this section.

Once a project is in the approved work plan, Electric Capital Delivery manages the overall project until it is commissioned as an in-service asset. The Capital Delivery project manager for a project convenes the project team and develops a project schedule. System Engineering prepares a detailed scope and bill of materials from the project scope, which further develops the schedule and budget. The project manager continues to monitor the schedule and budget through construction and commissioning. Project close-out is completed after commissioning, demobilization, and project final reporting are finished.

A project management program will also consist of project engineers to scope out and design the work. The number of project engineers in the company is minimal in both the transmission engineering group and the substation engineering group. As a result the use of engineering design contractors is extensive. This is shown in the table below.

Resources	Internal	Contracted
Project Engineers - Transmission	2 engs & 2 techs	26
Project Engineers – Substation Design	2 engs & 1 analyst	39
Project Engineers – Substation Protective Coordination	6 engs (3 are vacant) & 1 analyst	

The functions being contracted out in transmission and substation engineering are shown in the table below. Transmission engineering enjoys the advantage of nearly all construction work being Greenfield construction of new structures. As a result they are able to leverage the use of standard construction drawings and materials. This enables them to maintain more control over the contractors. Substation engineering does not have this advantage. Most of their work is rebuilds requiring custom engineering to accommodate a wide range of existing equipment. As a result the substation engineers are now functioning as an internal contact person only.

Function	Transmission Engineering	Substation Engineering
Preparation of detailed designs	Contracted	Contracted
Review of detailed designs	In-house	Contracted
Preparation of conceptual design	In-house	Contracted

The annual billing costs of a contracted engineer average $134,000 more than the average in-house Engineer/Lead Analyst salary, including benefits.

ii. Team of Project Managers

A team of project managers should exist that have experience in all elements of project management and have suitable credibility within the necessary work processes.

There are seven project manager positions. At the time of the audit data-gathering phase (May 2011) one of these positions was vacant. The six project managers were managing projects in various areas of the company before the Electric Capital Delivery group was formed. All have past job experience in this area. The technical background and qualifications of the project managers are varied.

- Four of the six have engineering degrees
- None are registered engineers (one has an Engineer-in-Training registration)
- One is a registered PMP (Project Management Professional)

Overall there is a lack of emphasis on certification and professional registration.

The number of project managers has not been adequate to get the projects completed. The track record for spending on large projects (greater than $1M) at NYSEG is shown in the table below. The RG&E data shows a similar pattern. Over half of the budgeted projects were never able to even get started. These projects are shown in the table with zero dollars in actual charges for the budget year. The remainder of the projects shows a pattern of considerable underspends. It is noted that a considerable amount of engineering effort and project management was devoted to two large transmission projects in 2009 and 2010. These projects were the Ithaca 345 kV line and the Corning Valley substation and associated 115 kV line. The Ithaca project accounted for $36M of the 2009 $39M actuals. Both projects together accounted for $58M of the 2010 $68M actuals.

NYSE&G	Capital Budget Results - 2008 to 2010 ($ in 000's)				
		# w/ $0 Actuals		Remainder	
Year	# of Projects	#	Budget $	Budgeted	Actuals
2008	63	32	14,254	38,712	11,937
2009	47	33	8,850	66,664	39,256
2010	60	33	11,541	77,169	68,586

The number of project managers has been increased through the use of contractors. In March 2011 an Owner's Engineer contract was put in place with SNC Lavalin. This group will eventually take over most of the project management responsibility. SNC Lavalin is a multi-national firm with offices in Canada.

Owner's Engineer is a title given to the representative of a construction or engineering project. Owner's Engineer is an independent third party or contractor. They undertake technical due diligence on the owner's behalf to verify the project is being constructed according to scope and specifications. An Owner's Engineer role is generally separate from the role of the Project Manager. In this case SNC Lavalin is providing project management services in addition to providing technical due diligence in the traditional Owner's Engineer role.

The number of project management contractors being employed can be glimpsed by looking at the details in the April 2011 technical services billing data. Seven engineering companies billed for services in this month. This data is shown in the table below. The SNC Lavalin numbers for project managers are low due to their contract only being in place the previous month. These numbers are expected to increase considerably. SNC had a CRO (Contract Release Order) dated May 23, 2011 for $2.5M of Owner's Engineer services on RG&E projects. A similar CRO would be issued for NYSEG projects.

April 2011 Data	Number	Hours	Full-Time Equivalents
Total people billing technical services	187	9,727	58
People titled Project Mgr. or Project Coordinator	28	856	5.1
SNC Lavalin employees	24	1,000	6

The annual billing costs of a contracted Project Manager average $157,000 more than the average in-house Project Manager salary, including benefits.

iii. Large Projects Provided with Dedicated Support Resources

Large projects should be provided with dedicated support resources, including planning, scheduling and cost engineering skills.

aa. Estimating Systems

The primary Work Management System used at RG&E and NYSEG is the SAP Work Management System. Estimating of electric distribution projects utilizes the SAP work management system. Estimating of electric transmission and substation projects is done utilizing separate in-house computer applications.

(1) Transmission

The transmission estimating application is Excel 2003 based in a spreadsheet known as the Overhead Transmission Engineering Estimate. For transmission construction projects, estimates are developed in this spreadsheet. All transmission costs are derived from SAP and compatible unit (CU) costs are maintained within the SAP application. Each unit of property has its own CU. Macros are utilized so a group of CUs can be used for one structure. Transmission does all of the line estimates in-house. The contractor will provide the material and labor information to Transmission Engineering for entry into the estimating tool. A contractor will enter the actual work order information into SAP. Each section of line in a township must be entered in SAP in a separate work order.

There are four types of transmission estimates. The type is selected in the Excel sheet. The four types are:

- Preliminary – This estimate is based on typical mile prices and has high contingencies.
- Ballpark – This type of estimate has the same contingency range as Preliminary, but more time is spent on it. The only difference is the amount of time spent on it.
- Budget – The Manager of Transmission Engineering approves and communicates these figures to the appropriate people.
- A/E (Authorized Expenditure) – This estimate will be forwarded for approvals per the written corporate documentation and procedure.

The version of Excel being used is 2003, which is many years and several versions out of date. They used to do studies on the estimating accuracy by conducting look backs but no longer have the people to do this. It is also noted that the SAP requirement for a separate work order for each township is cumbersome and often generates construction packages that are confusing to follow.

(2) Substation

The substation estimating application is an Access based program known as the Substation and Protection Engineering Estimate Program. This tool provides estimates for overall substation, protection, technical services, control house, buswork, conduit and control cable, grounding, and structure items. The estimating tool has current prices for the different items. Actual costs are compared to estimated costs for the items. When the actual cost for an item is different, it will be updated in the estimating tool manually. This keeps the overall item prices accurate. Rarely is a project estimate compared to the actuals. Similar to transmission, there are ballpark, budget and A/E estimate types.

The actual substation equipment and work order information is entered in SAP. A WBS number is set up for the project. Substation work orders need a capital install work order and a removal work order entered. These work orders are needed for internal time charging. When a piece of equipment is installed, it will have an associated number of labor hours with it that is part of the estimate.

(3) Distribution

The cost estimation process used for distribution projects consists of the creation of compatible unit (CU) work orders in SAP. Compatible units (CUs) are pre-coded construction assemblies where the materials, estimated labor, and estimated vehicle use for a specific task are contained. The use of these task-level CUs minimizes the time it takes to create work estimates and adds a higher degree of accuracy and consistency to the cost estimating process. Each operation in a CU work order is assigned an activity type that specifies the estimated labor rate for the work center crew that will perform the work. This activity type has an estimated hourly cost associated with it. The estimated hourly rate is based upon existing labor rates. Allowances for contingency funds for additional work unique to the specific job site can be added to the CU work order by the engineering designer at the time of work order creation.

Of the three areas, distribution is the only one where the designers are in-house and must interact with SAP directly for estimating and work order entry. Three distribution engineers were interviewed on various topics. All were very vocal in describing SAP as an extremely cumbersome tool for work order entry.

bb. Work Management Systems - SAP

The SAP enterprise is not used for work management tracking by any of the three areas. Transmission Engineering has an Excel spreadsheet that is used. Substation Engineering uses a Microsoft Access database that was implemented in the early part of this year. They formerly used an Excel spreadsheet. The database is set up in a tiered fashion with more detailed information available from drill downs. Some of the information contained is the project scope, WBS# of work orders, budget info, dates, personnel assigned, major equipment info, milestone dates and status. There are no external links to SAP or other systems. The engineers are required to enter their project status information on a weekly basis.

For major projects a regional MERCS project meeting (Marketing, Engineering, Real-Estate, Construction and Stores) occurs once a month to coordinate the projects. A spreadsheet is used for the planning that keeps up with dates, materials and equipment. A supervisor in the region leads the meeting. No minutes are taken. The spreadsheet is kept on a shared site and everyone can update their status and sign-off on their work. Once a job is in construction it is no longer tracked in the MERCS meeting.

Distribution work consists of many small items in a separate work order in SAP. SAP is the only tool available for managing this volume of work. There were many issues and concerns mentioned by the distribution engineers regarding SAP:

- Due dates are mostly left open. There is no customer required date in the system. This must be communicated via emails. SAP has an internal email function. Most of the actual work assignments in SAP are carried out via emails. The engineers report that this is a struggle to manage.
- Cost approvals are redundant. Each individual work order is approved. Less than $20K approved by Field Engineering Supervisor, $20 - $50k approved by Field Engineering Manager, $50 -$200k approved by Director and greater than $200k approved by VP – Engineering Department. For example, on a large work order, the high contractor cost will require a cost approval through one channel and the materials purchase cost must be

approved through other channels. All this is in addition to the fact that the entire project has already been approved. The project approval form process is followed once a job has been estimated in SAP. The project approval form is approved outside of SAP. There is then a separate approval process to go thru in SAP for getting the project work order costs approved.
- Field designs are input into SAP. SAP is not a good tool for doing designs. There is a SAP module available for entering field designs outside of SAP and then downloading them into SAP. The Iberdrola version of SAP does not contain this module.
- For a large customer job, Field Engineering must contact Stores and order the materials. Stores cannot see the material need in SAP until the job is released to construction, which is too late due to the lead times required.
- The SAP implementation (2005) caused the loss of TLM (Transformer Load Management) system capability. Field Engineering can no longer monitor distribution transformer loads.
- Extensive searches (data mining) are needed to get any usable work management info. One small report on the TDIRP project list with actual expenditures to date took over 16 hours of engineering time to produce.
- A Master Data & Records Team composed of 20 people maintains the equipment records in SAP. The equipment records in SAP feeds into the GIS system. The ability to do an automatic update upon work order close-out was not added until March 14, 2011. They are currently 1 ½ years behind in loading as-built drawings into GIS from SAP. Seventeen temporary employees have been hired to catch up with this backlog. This data backlog is anticipated to be caught up by the end of 2011.

There are a number of SAP enhancements in process. The foremost of these is the SAP Rearchitecture Project. This is a $3.6M project for 2011, approved June 2011, that was not in the approved spending plan. The business case for the Rearchitecture Project was not specifically focused on Work Management. The business drivers of the project were much more broadly based. The key considerations include:
- Keeping key SAP and SAP-related software at current support levels.
- Making new functional enhancements from the latest enhancement upgrade available. Much of the enhancements provided by SAP in this release are focused on the Customer Care System (CCS – supports customer service, billing, credit and collection, etc.).

The four primary components of the SAP Rearchitecture effort are:
- Upgrade to SAP Enhancement Pack 5. EP5 also enables a number of functional enhancements. The most notable are enhanced credit and collection functionality and the standardization of compatible unit (CU) / Operational Level Costing (OLC) processing for Work Management. The existing version of CU was co-developed with SAP and is not part of the supported product. With EP5, it will be part of the core SAP product and as a result it will reduce support risks.
- Upgrade to Stream Serve Version 5 (used for bill formatting, work order shop papers, etc.)
- SAP Security Upgrade Review
- Implementation of Data Compression.

The nature of the SAP enhancement release is that you implement all of the upgrades that are part of that release.

Aside from this larger project, much of the SAP related enhancements are in the form of smaller, quick hit requests coming from the Business Transformation (BT) program. There are several BT teams that are focused on different aspects of business operations with the goal of identifying efficiency ideas that can be quickly implemented. By the nature of being quick hits, the list of current and planned requests changes quickly. The following is a sampling of some of the current and planned SAP related requests from BT in the arena of Work Management:

- Master Data – Automate master data update processing to reduce the amount of resources required to complete.
- Resource Planning – Implement a tool and supporting data sources to enable better modeling of field crew resource needs.
- Purchase Requisition – Provide further automation of purchase requisition creation and processing.
- KPI Reporting – Provide a set of standard KPI reports (with drill down capability) to enhance assessment of performance.
- MRP – Configure and enable standard SAP functionality for Materials Requirements Planning (MRP) to improve warehouse efficiency by automating the material planning and replenishment processes.
- Joint Use of Plant Tracking – Implement a process in SAP to track pole attachments by telephone and cable companies.
- Customer Email Notification – Automate the sending of status update emails based upon task completions in SAP.

iv. Project Manager Role Definition

The role and responsibility of the project manager should be clearly defined and understood throughout the organization.

For substation and transmission electrical capital projects, the Project Manager is directly accountable to the Manager of Electric Capital Delivery. The expectations for the position include managing the project to the budget, scope, and schedule established for the project and identified on global terms on the project authorization form – Post Budget Authorization Form (PBAF).

The project manager typically performs the following tasks on an ad hoc basis:

- Assemble project team
- Develop detailed task breakdown list and associated project schedule from project scope
- Hold project kickoff and periodic team meetings
- Manage procurement, engineering, and contracting tasks
- Track and manage project costs against the budget
- Review and approve invoices
- Review and authorize project change orders
- Report to management

- Manage project documentation

This role had not been defined at all in written procedures. As Iberdrola USA reorganized its Asset Management and Project Management groups in 2010, the specific details of the project management roles and responsibilities are currently under revision. A Project Management Procedures Manual is scheduled for a draft release for internal review on June 1, 2011.

The concerns due to the lack of documented project management procedures are:

- Process flow and responsibility assignments are unclear.
- Lack of formal project charters containing hard dates, constraints and assumptions.
- Lack of defined project performance expectations for the key players.
- Lack of project management organizational charts.
- Project initiation and scope definitions are inconsistent.
- Lack of resource based project management planning.
- Lack of consistent milestone scheduling.
- Lack of a stage gate review process.
- Estimating packages do not match the work breakdown structures.
- Lack of estimating accuracy expectations.
- Lack of schedule performance expectations.
- Undefined contingency management process.
- Undefined project close-out procedures.
- Lack of any Lessons Learned process.

v. Expectations for Project Managers

Expectations for project managers should be consistent with the authority and resources given the project manager.

With the lack of any written project management procedures in place, the performance expectations are the only source of written consistent expectations. All six of the project managers had the same performance expectations in place for 2011. The only portions different were the training plans for each person, which are individualized. In general, these annual performance expectations are for the most part subjective. A goal or result is stated, but how it is to be measured is often left in doubt.

The categories of the performance expectations are:

- Completing Day-to-day Job Responsibilities – 10 percent weighting
- Capital Delivery Budget Performance – 25 percent weighting
- Owner's Engineer/Project Manager Coordination – 20 percent weighting
- Project Management Procedures Manual Development – 35 percent weighting
- Safety – 10 percent weighting.

vi. Project Management Requirements Consistency

Project management requirements for project participants should be generally consistent across all projects.

With the lack of any written project management procedures in place, consistent project management requirements were not found. The lack of a consistent process was mentioned in several interviews. Some of the requirements which were found to be inconsistent are:

- Initial handoffs for new projects - Still continuing to work on the processes
- Estimating accuracy expectations – No guidelines in place
- Engineering contractor rating/feedback system – None in place/under development
- Contingency fund management guidelines – None in place
- Construction/design bid comparison to budget estimate – No process in place
- Interaction of different contractor reviewer and contractor designer roles – None in place
- Project close-out reviews and process – None in place

vii. Project Management Principles Applied to O&M Efforts

Project management principles should also be applied to significant O&M efforts requiring cross-functional participation.

The large O&M projects are managed by the Electric Maintenance Delivery group. There are three main functional areas in Electric Maintenance Delivery. These areas are:

- Vegetation Management
- Electric Maintenance Engineering – Substations
- Electric Maintenance Engineering – Transmission and distribution lines

The vegetation management function is discussed in detail in Section III. The Electric Maintenance Engineering units are discussed below.

aa. Electric Maintenance Engineering – Transmission and Distribution

The primary goals of this work unit are to meet the state reliability goals. The primary job functions of this unit are:

- Develop and oversee maintenance programs for electric T&D lines (no substation work)
- Design any new maintenance programs and specifications
- Perform Q/A on the maintenance programs

Each project has an assigned Program Manager. The electric system is inspected and maintained on a programmatic versus a project basis.

The largest O&M effort is the PSC mandated Electrical Safety Standards Inspection Program. This program was mandated in 2005. It requires a five-year line inspection and stray voltage testing program (20 percent annually). There are two parts. The first part is a requirement for stray voltage testing. This is ground voltage differential testing done by special crews. The second part is the inspection by circuit for reliability and power quality concerns. The stray voltage program portion is a $7.3M program. It involves 50 field testers. There are also 17 Q/A Q/C coordinators and a Program Support contractor.

The plans for the inspection portion are developed on a Division basis. Each Division plan shows the specific circuits scheduled for inspection in that five-year cycle, or 20 percent of the system each year. The first inspection cycle commenced in 2005 and ended in 2009 and the second inspection cycle commenced in 2010. NYSEG and RG&E Transmission inspections for 2011 represent the second year of the second cycle. Company inspectors are given hard copy maps showing the circuits they need to inspect. When completed, the inspectors return the maps and deficiency documentation to the work unit. Maintenance Engineering then updates the Company's inspection database and develops various progress reports. Any deficiencies found during the inspection process are assigned a priority level for repair. These priority levels are associated with a repair timeframe which is monitored.

Other O&M programs that are conducted include:

- Cable Cure Program: This program is for old XLP stranded non-interstice filled cable that is located on the RG&E system. Older cable is injected with Cable Cure, which extends the cable life at a much lower cost over replacing the cable. The cable is selected based on the number of customers, age, past failures and whether it is on a looped system. There is an estimated 1,500 miles of this cable throughout the system. From inception of the program approximately 265 miles have successfully been treated to date at a savings of $20M.
- IR (Infrared) Program: This program is done cyclic at RG&E (five years mainline, ten years other) and ad hoc at NYSEG. It includes all substations, which are inspected annually. A SAP notification is sent out for repair of any items found.
- Helicopter Patrol Program: This program is for 115 kV lines and higher. Unlike the high speed flyover done by the vegetation management arborists, this is a slow speed patrol. The structure hardware is checked by hovering at each structure. Some items found are immediately repaired from the helicopter platform. These lines are on a five-year inspection cycle (flying or walking). Bulk transmission lines are flown and also walked every year.
- Pole Groundline Inspection Program: There has not been a cyclic groundline inspection program in place in the past. There is an inspection and treat program starting this year which will inspect 31,000 poles, mostly transmission.

Starting this year Electrical Maintenance Engineering is using the incremental maintenance approach ($7M in current budget) to be more proactive. Incremental O&M projects have been identified and recommended for 2011 – 2013 as part of Rate Cases 09-E-0715 and 09-E-0717 for NYSEG and RG&E, respectively. Projects include additional maintenance on specific categories of equipment including, but not limited to, transformers, circuit breakers, oil pipe cable, protective relaying, wood poles, etc. Projects are prioritized and scheduled by the Maintenance Engineers responsible for the respective categories of equipment. A budget has been established for the projects in accordance with the Joint Proposal resulting from the rate case and accounting has been created to capture the O&M expenses associated with each project. Projects are prioritized based upon improving system reliability. Incremental maintenance will be conducted by contract work force in accordance with the specifications developed for each project. Projects will be closed-out upon completion of work, quality assurance review, and payment of invoicing.

bb. Electric Maintenance Engineering – Substations

The primary job functions of the Substation Maintenance Engineering group are the maintenance planning, analysis and prioritization of the substation needs. The electrical substation O&M process is driven by ongoing equipment condition assessment. For the NY substation maintenance programs there are 6 Lead Analyst or Lead Engineers with similar job responsibilities. The largest part of their time is spent on field support activities. They are the technical experts for the test and repair procedures and software support for them. The next largest part of their time is spent on analysis and maintenance tracking of the test results. They issue the annual test requirements and track the results. They spend about 10 percent of their time on designing maintenance plans based on reviews of the intervals and conditions.

Circuit breakers are on a four, six or eight-year maintenance cycle. There is also special maintenance preformed for large fault tripping occurrences. Relays are on cyclic tests. For bulk transmission relays they track the tests in an Access database. For the others they use a manual tracking and scheduling system.

The Substation Operations group performs the on-site field maintenance work. The majority of all O&M work is completed with company resources. Contractors are utilized when necessary to supplement the company work force or when specialized services are required.

viii. Principles and Methods of Cost Management

The philosophies, principles and methods of cost management that are described in further detail under "Work Management" should be applied in the project environment. This includes the holistic approach, appropriate systems, measures, analysis, reports and corrective action requirements.

There are many programs where a holistic cost approach has not been applied in the past on project or program management. Two examples of this are the wood pole groundline treatment program and the vegetation management cyclic trimming program.

The wood pole groundline inspection program being implemented in a limited fashion in 2011 (31,000 pole program) did not have an associated business case study. The following rationale was cited: "The basis for the wood pole inspection and treatment proposal in the 2009 Rate Case was that wood pole ground line remedial treatment programs are the accepted industry best practice for extending the service life of wood poles, versus scheduled replacements based upon an estimated untreated service life. For this treatment, the cycle is generally recognized at ten years and the wood poles selected for the Rate Case were due for this maintenance." So while this type of program is known to be the long term lowest cost, only 1,370 poles were inspected and treated in the past five years. A 10 year groundline program would require 10,700 poles *per year* be inspected.

The distribution vegetation cyclic trim program is another example of a holistic cost approach not being followed. NYSEG is not funded for a full cycle distribution maintenance clearance program. RG&E has received some additional funding for 2011 that would enable it to start on a five year plan for full cyclic trimming. In response to a request for any VM study on going to cyclic trimming the following information was cited: "The benefits of a cycle-trim program have been well settled. Reports from the early 1990s all recommended implementation of cycle-trim programs, such as the 1993 report "Transmission and Distribution Operations and Maintenance Expense Volume 1" which refers to distribution maintenance cycles on page 21 (Attachment 1) and the "PACE OPS '95" report recommends a cycle line clearance program on page 92 (Attachment 2). These studies support NYSEG adopting a cycle line clearance program for distribution operations. In addition, the benefits of a cycle program have been documented in the utility industry as described in two articles "The Economic Impact of Deferring Electric Utility Tree Maintenance" (Attachment 3) and "Cutting Costs, Growing Performance" (Attachment 4)."

The cost/benefits of cyclic trimming have been known at least as far back as 1993, but have not yet been fully implemented. The lack of cyclic trimming is starting to show the long term cost effects. A September 2010 Distribution System Vegetation Workload Study found a significant amount of ROW growth (brush) 6 to 18 feet tall throughout the system. The study cited the following warning: "As brush matures over about 6 feet in height, maintenance costs start to increase significantly and maintenance options diminish. Allowing brush stems to mature will increase the likelihood that this vegetation will become part of the future trimming program rather than be maintained as brush acreage. This may have a significant impact on future tree trimming costs." It went on to additionally cite "….failure to maintain or control the brush population will result in much higher tree trimming costs in future years." The study also made the following observation about trees growing close to energized conductors. "Of significant importance is the 47 percent of the trees on the Iberdrola USA system that are within 4 feet of the conductors and have the potential to make line contact within two growing seasons. This could be a significant cost driver in future maintenance costs."

ix. Cost Management Plan for Major Components

Major components of the work should have their own tailored "cost management plan" that describes the baseline cost, who is accountable and how costs will be managed. Such plans should include the specific actions required of the cost manager and the supporting cost engineer.

There are several areas that were viewed to provide a better understanding of the cost management plan for the major work components. These areas were the budgeting requirements, the case studies (Corning Valley) and the procurement of major materials.

The budgeting form (PBAF – Post Budget Authorization Form) requires cost information broken down into the traditional buckets of capital, O&M, IT, etc. In addition it requires a breakdown into the following components:

- Company Labor
- Contract Labor
- Material

- Transportation
- Other.

Other cost information may be contained in the estimate that accompanies the form. Overall this breakdown is not sufficient for developing a cost management plan. A problem has developed. A detailed estimate is needed for this type of information. The detailed estimate is increasingly being provided by a design contractor. The design contractor cannot be employed until a PBAF form has authorized the project.

The Corning Valley case study contained a detailed estimate which described the baseline costs of the major work components. Each of the work areas had a separate estimated cost. The Project Manager functioned as the cost manager for each work component and the overall project. The design contractor functioned as the supporting cost engineer. The only cost accountability was to manage the overall project to within 110 percent of budget. The construction contracts were lump sum bids with a not to exceed amount. The construction work for each substation was broken down into three contracts – site development package, below grade package and above grade package. However, the detailed estimates were not developed in the same manner. This made it impossible to review each individual bid to determine its agreement with the estimated price.

The major material items in the Corning Valley case study had a detailed material procurement schedule and a detailed cost estimate. These schedules and costs were managed by the Project Manager. In the case of Corning Valley the Substation Engineer functioned as the supporting cost engineer.

x. Formal Approval of Projects

Formal approval and kick-off of projects should not be permitted in the absence of reasonably firm scope definition and a cost estimate whose quality is consistent with the current design status.

Investment Planning receives a prioritized project proposal from System Planning, Maintenance Delivery, and Asset Management, coordinates and combines those projects into the overall 5-year capital plan and the annual work plan. High priority project needs, including regulatory required (such as customer service related investment as detailed in the appropriate Filed Tariffs) and government required (including compliance with NERC and Department of Transportation requirements) are funded first in the investment planning process. Further projects are prioritized and funded based on system reliability needs and risks.

The Project Approval process begins with the initiation phase, which includes an initial project scope and associated cost estimate and benefit determination. The Investment Planning Group receives project request for authorization on a PBAF (Post Budget Authorization Form). An assessment is made related to the priority and forwarded for management approval as required based upon the total capital cost of the project and relative level of approval required. The decision to forward the project PBAF for approval is directly related to the priority of the project and the available funds in the capital budget.

The PBAF form (Post Budget Authorization Form) is a new form created in May, 2011 that replaces the UPAF (Universal Project Authorization Form). Every project greater than $100k needs a PBAF approved for initiation and authorization. The amount of the project determines the PBAF approval level. The PBAF approval is needed before a project is given a WBS number, which is needed for charges to accumulate in the SAP work management system.

Once a project is in the approved work plan, Capital Delivery manages the overall project until it is commissioned as an in-service asset. Since the design and construction functions are consolidated in Capital Delivery, the estimate accuracy at that time for large projects is often ballpark. As the detailed designs are completed, the substation and transmission estimates are both honed into a clearer A/E estimate.

xi. Exit Ramps for Large Projects

Large projects should contain "exit ramps" early in the job to permit management re-consideration if costs begin to escalate.

Once a project is budgeted it can remain in the execution phase as long as costs are within budget. For any project running a variance over 10 percent, the Project Manager must submit another PBAF (Post Budget Approval Form) with revised costs for management approval. This provides management with a chance to reconsider the project.

xii. Program of Scope Control

A program of scope control should be in place that identifies scope deviations early, requires analysis of such deviations and the mandatory specification of alternates to mitigate the effects of the deviation.

Management controls and processes in place for the monitoring of costs associated with transmission and substation electrical projects begin with approval of the Post Budget Authorization Form (PBAF). The PBAF defines the scope of work, cost, schedule and project justification, and requires approval of the appropriate level of executive management based upon total project capital cost. Any cost increases of over 10 percent require another PBAF be submitted and approved.

Design and construction contractor scope changes are dictated by project needs and requirements, and agreed to in writing in accordance with the terms and conditions of the project agreement. Any authorized scope change must be in the form of a written change order referencing the original project agreement. The change order will define scope change and any schedule or cost impacts. Management authority to execute change orders to a project is delegated in the project agreement, and also in accordance with the aforementioned Procurement Services Policy Manual.

The monitoring of general problems which can lead to scope changes includes the following:

- Project and Program Variance report meetings, which include operating company executives, are held monthly at 3 different levels to review work progress and monitor budget expenditures.

- Project and capital tracking spreadsheets are employed to report expenditures and variances to the Asset Management & Investment Planning department and executive project sponsors.
- General problems related to construction, installation, schedule delays or payment issues are addressed and documented during weekly project progress meetings.

The controls and processes in place for the monitoring of costs associated with distribution electrical projects begin with the approved capital budget. The capital budget contains funding allocation for distribution programs that are intended to provide a source of funding for all minor Capital Distribution projects that are initiated, engineered and constructed at the division level with division resources. These programs are managed like large capital projects, including monthly management reporting. Any job expected to exceed the distribution major project level (greater than $100k) requires prior approval and justification.

Distribution projects are designed in the SAP work management system using Compatible Units (CUs). The CUs contain the material, labor, and vehicle charges for that component, along with the appropriate accounting for the operation (install, remove, transfer). Before the work order is ready for construction, the cost of the project is formally approved in SAP at the appropriate level of authority.

Scope changes associated with distribution electrical projects are handled on a job-by-job basis. The division engineers work with the constructions crews to determine out of scope items that need to be addressed. Any out of scope items identified, such as the need to change-out additional unitized property items are drawn up by the engineers for approval. Unexpected costs, like rock holes or flagging, can be charged to the work order without prior approval. The Operations department can obtain these additional services needed and charge them to the work order. A significant problem would require a redesign by Field Planning and most likely the issuance of an additional work order.

xiii. Collective Management of Small Projects

The construction program should have provisions for the collective management of small projects, as opposed to the standard project management approach.

Small projects are generally the routine work that is processed on a regular and ongoing basis. In many instances this routine work is grouped and managed under programs. For instance a utility would have a pole management program for all of the thousands of wood pole inspections and replacements, or an underground cable management program for replacement of the many individual spans of older underground cables.

For the collective management of small transmission and distribution system infrastructure improvement projects, the TDIRP program provides a good vehicle for collective management. Projects are to be aggregated by type for budget and budget monitoring, collective program management and consistency.

The substation routine projects are more involved than the transmission and distribution projects. Many of these substation projects are rework or equipment replacement involving custom design solutions. One critical element to the substation project schedule is the amount of time to get a detailed design in place. A detailed design is needed before the construction work can be bid out. These projects are bid out to design contractors on a lump sum bid. The RFP process for getting a major design contract (greater than $100k) in place has a guideline of 88 business days (four months of total time) to allow for the process. A project requiring both conceptual and detailed design RFPs will have at least eight months of RFP time plus the actual design time itself.

Due to the lack of internal substation design staff, many small routine projects are bundled together and bid out as one large project. Therefore both large and small projects must now go through this lengthy design RFP process.

A good example of the common small substation project is the replacement of obsolete circuit breakers. Prior to 2010 about 60 breakers each year were replaced. Future replacements are anticipated to be about 100 to 120 breakers each year. Each of these breakers is generally a separate project due to their locations in separate substations spread out across the entire state. Substation design should have a smooth work management process and flow for this routine work rather than requiring it to be treated like a large project.

xiv. Project Management Program Applicability

The project management program should apply to all organizations participating in a project, whether internal or contractors.

There are a large number of contractors participating in the project management process. In addition to the design contractors, a contractor (SNC Lavalin) is now directing the overall project management process. The contractors are not only participating, but taking the lead role in the project management process. They are also participating in drafting the Project Management Manual sections. As of September 2011 they provided 239 hours of effort on drafting this manual.

xv. Relationship of Quality, Cost and Schedule

The role of quality and its relationship to cost and schedule achievement should be clearly defined and understood by all project participants.

The three main objectives of project management are cost, quality and time. The mix of these three elements is the overall scope of the project. No one element can be sacrificed at the expense of the others. However, one of these three elements will be the driving factor for the product. This will determine how the project should be managed. For electrical systems, the technical performance of the system, or quality, is the driving factor. It is a quantified deliverable that must be met.

Design and construction contractors play a critical role in the overall quality of the project. One procedure for maintaining quality is the technical evaluation in the RFP process. This evaluation includes a judgment on the ability of the bid proposal to deliver the quality requirements in the final product or service being procured. This helps to reduce the risk of poor quality.

Quality control for electrical systems is maintained by the use of proven construction standards. Substation, transmission and distribution had detailed construction standards in place. These standards help to ensure uniform designs and common materials are used. This controls quality by improving the consistency of the final product being delivered.

Some other observations on quality procedures in place included the following:

- Substation commissioning procedures were in place for final quality checks. This included the budgeting, contracting and scheduling of these procedures.
- Dedicated field supervision for monitoring the construction process was in place in the case studies.
- Q/A Q/C inspectors were in place for monitoring the activities on the O&M programs.

Overall, there were not any written Q/A Q/C procedures that required the above functions to be in place. The Project Manager discretion was the main driver for setting up the Q/A procedures on a particular project.

There are two aspects of contractor quality. First, the contractor quality must be monitored while the work is in progress. Later, the overall quality performance must be judged. This performance would affect the contractors' ability to gain future contracts with the company.

Contractor performance issues are addressed using the proper notification process within the provisions of the project agreement. The notifications are normally written and allow for a curing period prior to further corrective action being taken. Supplier Corrective Action Report (SCAR) is used as an additional tool beyond other written and verbal notifications. This form provides feedback to Procurement Services on Supplier/Contractor performance and is kept on file for future reference. Upon project completion a Contractor Performance Scorecard is completed by the appropriate project personnel and submitted to Procurement Services to grade the contractor's performance on work performed and to address deficiencies. It is also kept on file and used as part of the qualification process for future work.

Liberty observed there were not any scorecards in place for the evaluation of the contracted project management or design engineering personnel. The development of a scorecard for performance evaluation of Project Management and Project Engineer vendors is currently part of a comprehensive QA/QC program being developed.

xvi. Linkage between Project Management and Budgeting

There should be a clear linkage between project management and the budgeting systems, characterized by input from and feedback to those systems.

The SAP work management system is excellent for accumulating actual cost data in a timely manner. Other than that feature it is limited in its' ability to provide good project management data. Project and capital tracking spreadsheets outside of SAP are employed to report expenditures and variances. Also, when the projects are estimated the costs are broken down by company labor, contract labor, materials, transportation and other. Only the total budget cost is loaded into SAP. As a result the cost tracking outside of SAP gives a much better picture of what is happening.

The typical SAP financial reports compare the actual expenditures to the initial plan. Currently there is a limit on only one cash flow budget being loaded into the system for the year. There are not any updates done during the year. The Project Managers have the data available and track it outside of SAP for their project reports. The monthly and year-end budget variance reports are interspersed with explanations on why the SAP figures do not match what is actually occurring. The Iberdrola method in use in Spain is to update cash flows at one 1 plus 11(January), 4 plus 8 (April) and 7 plus 5 (July). This would be an excellent method if it were in place at Iberdrola USA. Note that this process changes only the cash flow patterns, not the approved budget amounts. Approved budget amount changes are done through the scope change process.

The Revision (REV) process is an extension of the overall budget process. Each REV evaluates the company's current conditions and budget assumptions are adjusted using actual results and updated/current assumptions. During the REV process each functional area is responsible for updating their projections for the remaining periods for the areas in which they are responsible. For example, the Engineering & Asset Management functional area is responsible for updating their P&L expenses as well as Capital projects.

During the REV process there are three financial statements being produced:

- P&L
- Cash Flow
- Summary Balance Sheet.

The P&L is the only financial statement currently updated in SAP, with the balance sheet and cash flow being maintained outside of SAP. They have currently begun a process to have the CapEx portion of the Balance sheet updated in SAP. They are in the initial stages of this process with a goal to have this in place for 2012 REV1 which occurs in March of 2012.

xvii. Defining Project Priorities

The relative priority of projects and programs should be defined in the planning and budgeting process and, once projects have been approved, assigned and scheduled, those priorities should be moot (i.e., the project manager should not have to compete for resources).

The priorities for the substation, transmission and distribution capital projects are being set in the planning process by the respective engineering units. The project origination and prioritization process is described in detail in sectionC.2.a.ii. Brief descriptions of the processes are:

- System Planning – Three metrics (MW load at risk, number of customers at risk and hours of exposure) are used to rank all projects in priority order.
- Electric System Engineering – Distribution planning studies are performed and generate a list of all the system improvement and capacity items. These are then ranked in a priority order.
- Electric Operations - Minor capital improvements, meters and transformers, road relocation projects and large underground projects are compiled and ranked.

- TDIRP (Transmission/Distribution Infrastructure Replacement Program) Team - Project selections are based on operating condition priorities, maintenance history, line and/or equipment obsolescence and maintainability, and required increases in system reliability. Substation Engineering, Transmission Engineering and Electric Operations provide project lists of prioritized items for their areas of responsibility.

Once these lists are prepared they are sent to Asset Management and Investment Planning for incorporation into the capital budget. The relative priorities remain fixed through the budgeting process. These projects are then sent to Capital Delivery for execution. The Project Managers in Capital Delivery do not compete for financial resources.

Similarly, the maintenance programs are prioritized in Electric Maintenance Delivery and then sent to Asset Management. Once the projects are budgeted the program managers in Electric Maintenance Delivery do not compete for financial resources.

xviii. Process for Contingencies

A process for the handling of contingencies should be defined and the "owner" of budgeted contingency funds for purposes of funding approvals should be identified.

The following contingency percentages are currently being used for estimates.

	Substation	Transmission
Ballpark	46%	55%
Conceptual/Budget	36%	45%
AE/Work Order	26%	35%

Distribution projects are typically smaller in size and shorter in duration than substation and transmission projects. The designers are able to usually field visit the construction locations prior to doing any estimates. Therefore most distribution estimates are AE/Work Order quality estimates with contingencies at 10 percent to 20 percent based on the judgment of the designer and the amount of unknowns (for example rock).

In the Corning Valley case study, there was no defined contingency control process or procedures followed. The Project Manager tracked the contract change orders and managed them against the overall budget. The detailed estimate from the design contractor included a 10 percent contingency fund based on the total project cost. The Corning Valley project was managed within this 10 percent amount. The original construction contractor bids were well under the amounts estimated. This enabled the PM to successfully manage the project costs below budget despite the high change order amounts. The total change order amount of the construction and design contracts was $4,962,289. Overall the construction contracts totaled $20.5M, which is 39% of the budget, and accounted for 93% of the total budget's contingency fund.

xix. Management of Turn Key Projects

Project management principles that define requirements for contractor project management programs on "turn-key" projects should be in force.

As discussed in detail in section C.2.c.iv, there are no written project management procedures currently in place. The vast majority of the projects involve either substation rework projects or common wood pole construction projects. These types of projects do not tend to have economies of scale that lend themselves to turn-key contracting. In late 2010 a group of eleven NYSEG transmission projects were lumped together with an RFP for a turn-key contract (engineering, procurement and construction). None of the responses to this RFP were accepted.

3. Conclusions

1. **Internal engineering resources are very low and the extensive use of contracting has not been justified.** (*Recommendation #1*)

The number of project engineers in the company is below the minimal levels required for routine work in both the transmission engineering group and the substation engineering group. As a result the use of engineering design contractors is extensive. A similar concern exists for the number of Project Managers. There are six internal Project Managers.

There have not been any business case studies to justify this level of contracting. The bulk of the contracting in question is for routine work that is normally done in-house in the industry.

The annual average in-house Project Manager salary with benefits is $124,000. The annual billing for a full-time equivalent contract Project Manager is $281,000. The net cost advantage of internal personnel over contracted is $157,000. The annual average in-house Engineer/Lead Analyst salary with benefits is $97,000. The annual billing for a full-time equivalent contract person is $231,000. The net cost advantage of internal personnel over contracted is $134,000.

The actual cost savings possible from using more in-house personnel would be based on achieving the proper balance of internal personnel. It is recognized that the use of some contracted personnel is desirable for workload fluctuations. The numbers below are a conservative estimate.

Total Cost Savings				
Position	**Per Unit Savings**	**Number**	**Total Savings**	**Level of Contracting**
Project Manager	$157,000	3	$471,000	PM contracting still needed for major transmission lines, new substations and workload peaks.
Engineers	$134,000	6	$804,000	PM contracting still needed for major transmission lines, new substations and workload peaks.
		Total	$1,275,000	

In addition to the cost issue of contracting, the lack of adequate internal engineering staff can contribute to limited time for other issues. These issues could adversely affect project management by either not providing program support or taking valuable time away from project oversight. Some of these issues are:

- Review of quality/cost tradeoffs being done by the design contractors
- Maintenance of construction and material standards used by the design contractors
- Maintenance of approved material vendors
- Maintenance of project management procedures
- Follow-up on defective material issues
- Follow-up on issues coming from the Lessons Learned project close-out process
- Maintenance of as-built project files and drawings
- Participation in the standardization process of combining companies
- Participation on business transformation teams
- Participation in the budget process

Overall, there are not enough internal project engineers and support staff to maintain adequate design and management control of the project management program.

2. **The existing team of project managers has sufficient experience in all elements of project management and has suitable credibility within the necessary work processes.** *(Recommendation #1)*

There is currently a team of six Project Managers in place. Liberty has reviewed the resumes of all of these Project Managers and interviewed most of them. Overall, these individuals are experienced and qualified.

As mentioned above, the numbers of in-house Project Managers are not adequate for the normal volume of work. Contract resources are used to supplement this work function. Liberty finds that a better balance of internal Project Managers versus using contracted resources could save $471,000 annually (see table in section above).

In addition to the cost issue of contracting the Project Manager functions, the lack of adequate internal staff can contribute to limited time for other issues. These issues could adversely affect project management by either not providing program support or taking valuable time away from project oversight. Some of these issues are:

- Maintenance of project management procedures: 35 percent of their 2010 performance expectation requirements are devoted to this activity.
- Follow-up on issues coming from the Lessons Learned project close-out process
- Participation on project management activities outside of the electric capital delivery program such as the sale of fossil assets
- Participation on business transformation teams
- Participation in the budget process.

3. **The SAP Work Management system needs changes to be made fully supportive of project management needs.** *(Recommendation #2)*

The primary Work Management System used at RG&E and NYSEG is the SAP Work Management System. All of the different types of electric distribution, transmission and substation projects flow through the SAP work management system. The SAP enterprise management system has good financial management tracking functions. The work management functions are cumbersome. Both Transmission Engineering and Substation Engineering have work a-rounds for this process. However distribution by necessity must use SAP for work management. To improve this process, the SAP system needs enhancements added.

The work management concerns that were identified are listed below. There are a number of enhancements planned or in process. Some of these needs could already be in the process of being addressed by these enhancements.

- **Email management & notifications –** This might be addressed by the enhancement on the automated email feature.
- **Redundant cost approvals –** This might be a process issue more than a software issue.
- **Work Order input –** This need might be addressed by using a module to develop work order designs outside of SAP and then download them into SAP. These modules are common solutions for these concerns.
- **Visibility of material needs –** This might be addressed by the MRP enhancement module (Material Requirements Planning).
- **Report outputs –** This might be either a training issue or a software issue involving standardized report templates.

4. The roles and responsibilities of the project manager are not clearly defined and understood throughout the organization. *(Recommendation #3)*

Overall the project management maturity level in place is ad hoc, which is the lowest level. Each Project Manager is free to manage the project their own way. This role has not been clearly defined. There are no documented project management procedures in place. A Project Management Procedures Manual is being drafted that will provide written definition, but it is not yet in place.

5. Expectations for project managers are consistent with the authority and resources given the project manager.

Overall, Liberty found the annual performance expectations for each project manager are consistent. All six of the project managers had the same performance expectations in place for 2011. The only portions different were the training plan for each person, which is individualized.

6. Project management requirements for project participants are not generally consistent across all projects. *(Recommendation #3)*

Project management requirements are not consistent or documented. A Project Management Procedures Manual is being drafted that will provide written requirements, but it is not yet in place.

7. Project management principles are applied to significant O&M efforts requiring cross-functional participation.

Liberty found that the significant O&M efforts had project management principles in place. This work was centralized and managed by the Electric Maintenance Delivery group. Project or program managers were assigned to each program. The work scopes were defined. The inspection and repair work was being scheduled and monitored. Contractors had field oversight in place. Reporting and record systems were in place.

8. A holistic approach to project management is not applied. *(See Chapter XIII)*

Liberty found that there are many programs where a holistic cost approach has not been applied in the past on project or program management. Two examples of this which were noted are the wood pole groundline treatment program and the vegetation management cyclic trimming program.

A total holistic cost management approach would increase the company's effectiveness. This cost management concept and more detailed recommendations are covered in the work management section of this report.

9. Major components of work do not have consistently tailored "cost management plan" that describes the baseline cost, who is accountable and how costs will be managed. *(Recommendation #3)*

Liberty found that some major components of work, such as the construction contracts, did not have written cost management plans. While overall cost management goals of 110% of project cost were in place, the management details for specific cost items were not in place. There was no documented process for validating the construction bids. Some of the common work breakdown structures used in the bid RFPs was not matched in the estimating process, which precludes the possibility of proper bid validation. Cost management plans for major work components should be in place and documented.

Some of the major material items in the case studies were found to have detailed procurement plans and schedules in place. Good project management procedures for those items were being followed. Documentation for these procedures should also be in place.

10. Kick-off of projects should not be permitted in the absence of reasonably firm scope definition and a cost estimate whose quality is consistent with the current design status.

Liberty found that projects being initiated had reasonable scope definitions and were accompanied by an estimate of comparable quality. The projects were initiated via a UPAF (Universal Project Authorization Form) or PBAF (Post Budget Authorization Form) containing the scope definition. (Note: the PBAF form is now only used to make major project changes to budget-approved processes.) At the time the projects are being kicked off they are at budget approval status. The project estimate is often just a ballpark at that time since the project is not fully designed. A detailed estimate is done later in the course of the design work for the project.

11. Large projects contain "exit ramps" early in the job to permit management reconsideration if costs begin to escalate.

Liberty found that project procedures contained management reviews if project costs escalated. For any project running a variance over 10 percent, the Project Manager must submit another

PBAF (Post Budget Approval Form) with revised costs for management approval. This provides management with a chance to reconsider the project.

12. A program of scope is in place, and identifies scope deviations early, requires analysis of such deviations and the mandatory specification of alternates to mitigate the effects of the deviation.

Liberty found that a program of scope control was in place. Any authorized scope change must be in the form of a written change order referencing the original project agreement. The change order will define scope change and any schedule or cost impacts. Management authority to execute change orders to a project is delegated in the project agreement, and also in accordance with the Procurement Services Policy Manual.

13. The construction program does not uniformly provide for the collective management of small projects. *(Recommendation #4)*

Liberty found that provisions were in place for the collective management of small transmission and distribution projects.

There are no provisions in place for the management of small routine substation projects. This is primarily due to the lack of engineering staff requiring all designs to be contracted out. These projects must be treated like a large project to reduce the RFP contracting burden on the delivery unit.

The overall process for electric capital delivery is shown in the process chart in section C.2.a.i. It clearly shows the design function separate from the delivery function. It is common industry practice to keep these two functions separate. In actuality this is not the case. The delivery function has now taken over most of the management aspects of the design process, including design schedules. There are certain efficiencies gained by keeping these different functions separate. Design can focus on design contractor and design schedule management. Delivery can focus on construction contractor and construction schedule management.

The most common methods of design contracting are shown in the table below.

Bid Type	Description	Best For:	Advs. & Disadvs.
Lump sum bid	One set price for a defined scope of work	Individual projects with clearly defined work scopes	Advs: Fixed cost, most competitive process Disadvs: Time to set up, changes are cost plus
Time and materials bid	Hourly rates	Undefined projects or work scopes	Advs: Small projects, unknown work, fluctuating work levels, quick changes Disadvs: Lack of a fixed cost
Unit price bids	Fixed rate per unit of work	Work where the units can be defined and measured	Advs: Small projects, fluctuating work levels, quick changes, fixed costs, more competitive process than hourly rates Disadvs: All work units must be defined, time for initial setup

The lump sum RFP process is not efficient for routine substation work. More common design practices are to use design contractors as staff augmentation set up in annual contracts on a time and materials basis. Similar to how tree or line contractors are utilized for small individual jobs, a piece of design work is simply handed off to the contractor for completion. The 88 day RFP process for each job can be avoided. Many of the substation projects are routine circuit breaker replacements that can be designed using this method. Another method would be to set up annual contracts on a unit price basis. For example, a work unit could be for circuit breaker designs of a specific voltage level and/or amperage. Again, a piece of design work can be handed off to the contractor for completion with the cost and design time being known in advance.

The responsibilities for meeting the design schedules have been blurred between the design unit and the delivery unit. All projects requiring design are now routinely turned over to the delivery unit for RFP contracting. As a result the design and delivery functions are now no longer separate functions and shown in the capital delivery process chart.

The separation of the design and delivery functions can also allow for milestone, or stage gate reviews. Currently it is not possible to hold projects at the design stage. One benefit is the ability to aggregate a group of routine shovel-ready projects for one construction RFP, which is more economical. Another benefit is the ability to better manage capital budget construction funding by no longer budgeting construction funds for projects that will not have design completed in time for construction that year. The construction portion of the project budget funds can then be directed to another project that is ready for construction. This will also improve the ability to meet the construction budget.

14. The project management program does not clearly address contractors performing project management activities. *(Recommendation #3)*

There are a large number of contractors participating in the project management process. Liberty has found that these contractors are guided by the unwritten procedures. An Owner's Engineer is now directing the overall project management process. They are also participating heavily in drafting the Project Management Manual sections. The Project Management Manual should contain procedures on the participation and management of contractors in the project management program.

15. The role of quality and its relationship to cost and schedule achievement is adequately defined and understood by project participants.

Overall, Liberty found that the role and importance of quality is understood by the project participants. The fitness of the electric facilities to achieve their use, purpose and requirements are being met. Basic quality control procedures in place include formal substation commissioning plans and schedules, ongoing independent field construction presence and inspections and Q/A Q/C inspectors utilized as a routine part of the process. The facilities in the case studies also appeared to exhibit good workmanship and layout.

16. There are gaps in the linkage between project management and the budgeting systems. *(Recommendation #5)*

The SAP budget system reports compare actual spending to forecast spending on a monthly and year to date basis. Once the monthly forecast spending is entered, it is not updated during the year on a systematic basis. As a result the budget reports are no longer able to accurately compare actuals to forecasted spending. There should be a systematic process in place for updating the monthly forecasted spending during the budget year.

17. The relative priority of projects and programs are defined in the planning and budgeting process.

Liberty found that the priorities for the substation, transmission and distribution capital projects are being set in the planning process by the respective engineering units. Once these prioritized lists are prepared they are sent to Asset Management and Investment Planning for incorporation into the capital budget. The relative priorities remain fixed through the budgeting process.

18. A process for the handling of contingencies has not been defined. *(Recommendation #3)*

Liberty has found that a process for the handling of contingency funds is not defined or in place. This process should be clearly defined in the Project Management Procedures Manual.

19. There are not clearly defined project management principles for contractor project management programs on "turn-key" projects. *(Recommendation #3)*

Liberty has found that the requirements for contractors on turn-key projects are not defined or in place. These procedures should be clearly defined in the Project Management Procedures Manual.

4. Recommendations

1. Determine the best balance of the number of internal project personnel for the demands for Project Managers, Project Engineers and Schedulers. *(Conclusion #1, #2)*

The number of project engineers in the company is below the minimal levels required for routine work in both the transmission engineering group and the substation engineering group. As a result the use of engineering design contractors is extensive. A similar concern exists for the number of Project Managers. Achieving a balance of in-house personnel versus contractors would alleviate the concerns and is conservatively estimated to save $1.275M annually.

The bulk of the contracting work being done is for routine work that is normally done in-house in the industry. The existing team of six Project Managers is devoted full-time to monitoring contractors rather than working on routine work. The levels of internal personnel do not appear to be enough for proper project review and monitoring. A loss of project control, in addition to the cost factor, is a concern. A loss of corporate project management capability through the overuse of contractors is also a concern.

The current level of internal Project Managers and engineers has not been adequate to get capital projects started and completed. As a result the capital budget has shown a history of underspends and budget projects that were not constructed. In addition to facilitating the construction work, the internal engineers and Project Managers contribute to corporate efficiency by participating on Business Transformation teams, helping prepare the budget, maintaining procedures and material standards and participating in the standardization process across Iberdrola USA.

Overall, Liberty believes that there should be internal engineers and Project Managers at a level that would handle the base workload of routine work. Contractors would still be an important component for handling large projects, specialty work and workload fluctuations above base.

2. Improve the project management functions of the SAP system. *(Conclusion #3)*

There are many SAP enhancements in process. The foremost of these is the SAP Rearchitecture Project. This is a $3.6M project for 2011, approved June 2011, that was not in the approved spending plan. The business case for the Rearchitecture Project was not specifically focused on Work Management. The business drivers of the project were much more broadly based.

Some of these enhancements will improve the project management and work management functions. It is uncertain if these enhancements will address all of the distribution concerns noted in the audit. These concerns should be reviewed. Any concern which is not already being addressed by a planned or in process SAP enhancement should be implemented.

SAP is an enterprise management system. It has good financial management and tracking capabilities. The work management functions are cumbersome. An enterprise system is designed for corporate-wide management rather than the management of small project details. As a result this software is enhanced by a suite of programs to customize it for a particular use. The SAP system needs these enhancements to better function as a distribution project and work management tool.

The main areas of concern that should be addressed by enhancements are:

- SAP internal email management and notifications are not automated.
- Redundant cost approvals are required by SAP.
- Work order designs cannot be created outside of SAP and then downloaded into SAP. This feature is a larger time saver for engineering.
- Material needs are not always visible.
- Report outputs are cumbersome.

Any cost savings from this recommendation are based on process improvements. Quantification is not possible until a specific solution has been identified and its impacts can be measured. Even then, quantification may or may not be practical.

3. Issue written project management procedures. *(Conclusion #4, #6, #9, #14, #18 & #19)*

The roles and responsibilities of the project manager should be clearly defined and understood throughout the organization. It is a recognized industry practice that these procedures must be documented for consistency of application, control and training. A Project Management Procedures Manual was scheduled for a draft release for internal review on June 1, 2011. It is not known at this time if these procedures will address all of the issues and concerns found in this audit.

The concerns Liberty noted due to the lack of documented project management procedures are:

- Process flow and responsibility assignments are unclear. This is a major issue on large projects where several layers of contractors are involved.
- Lack of formal project charters containing hard dates, constraints and assumptions.
- Lack of defined project performance expectations for the key players, including internal personnel and external contractors.
- Lack of project management organizational charts.
- Project initiation and scope definitions are inconsistent.
- Lack of resource based project management planning.
- Lack of consistent milestone scheduling.
- Lack of a stage gate review process.
- Estimating packages do not match the work breakdown structures. As a result the construction bids cannot be verified against the estimated costs.
- Lack of estimating accuracy expectations. As a result the overall estimates are not accurate. The project designer's estimates should be compared to the final design and be within expectations, usually within 10 to 25%.
- Lack of schedule performance expectations.
- Undefined contingency management process.
- Undefined project close-out procedures.
- Lack of any Lessons Learned process.

It is recognized that the benefits cannot be practically quantified. Project management planning is a basic productivity improvement process. Project management procedures are designed to improve the project delivery process. The benefits of improving the project management procedures are known to be:

- Decreased project costs
- Improved project schedules
- Improved employee productivity
- Improved budget monitoring

4. Separate the design function from the delivery function. *(Conclusion #13)*

The capital delivery process shows the design function separate from the delivery function. In actuality this is not the case. There are certain efficiencies gained by keeping these different functions separate. Design can focus on design contractor and design schedule management. Delivery can focus on construction schedule management. One barrier to this approach is the lack of in-house project engineering personnel. This is addressed in Recommendation #1.

The normal stages of large utility electrical projects are design, engineering, installation and testing. Many companies will have milestone schedules based on these stages. It is important to distinguish design from engineering. Design is concerned with the overall conceptual project scope and deliverables. Engineering is concerned with the physical materials and layout details necessary to achieve the project deliverables. Since both of these functions are carried out by engineers, design and engineering are often combined for small projects. For large projects engineering is an entirely separate function from design.

Liberty is concerned that the management of design contractors in the Capital Delivery organization could have adverse effects on the overall conceptual project scope and deliverables. There are certain efficiencies gained by keeping the design and delivery functions separate. Design can focus on design contractor and design schedule management. Delivery can focus on contractor and construction schedule management. The merging of these two functions has created the following issues and concerns:

- Increased design costs and inefficient use of design contractors. One primary factor in reducing design costs is to use more in-house engineers rather than contractors. This has been addressed in Recommendation #1. Adequate in-house staff is a prerequisite to efficiently managing design contractors. The lump sum RFP process in use is not efficient for many small routine engineering jobs. More common design practices are to use design contractors as staff augmentation set up in annual contracts on a time and materials basis. Additional efficiencies can be achieved by reducing the number and amount of engineering contractor interactions that must occur. One contractor used for staff augmentation with fulltime workers requires less orientation and interaction time than several companies with part-time workers.
- Inability to meet the planned construction budget spends. The ability to meet a project schedule is a critical element. One critical element to the substation project schedule is the amount of time to get a detailed design in place.
- Inability to perform design stage gate holds to aggregate routine jobs for more economical construction contracts. The separation of the design and delivery functions can also allow for milestone, or stage gate reviews. Currently it is not possible to hold projects at the design stage in Capital Delivery. One benefit is the ability to aggregate a group of routine shovel-ready projects for one construction RFP, which is more economical. Another benefit is the ability to better manage capital budget construction

funding by no longer budgeting construction funds for projects that will not have design completed in time for construction that year.

This recommendation is a process improvement that is not expected to require any implementation or ongoing costs. It is expected that design contractor savings can be found by a more efficient management of the design contract process.

5. **Adopt a systematic process in place for updating SAP monthly cash flows during the budget year.** *(Conclusion #16)*

A key feature of a project management budget system is the ability to accurately compare actual spending with forecasted spending. The current SAP process does not have a systematic process for updating the monthly cash flows during the budget year. An updating process would provide a clearer picture of the budget status of each project.

As the result of only loading an initial cash flow pattern for the project, the cash flow Year-to-Date budget and project reports become more misleading as the year progresses. The monthly and year-end budget variance reports are interspersed with explanations on why the SAP cash flow figures do not match what is actually occurring.

Once the monthly forecast spending is entered, it is not updated during the year on a systematic basis. As a result the budget reports are no longer able to accurately compare actuals to forecasted spending. There should be a systematic process in place for updating the monthly forecasted spending during the budget year. An updating process would provide a clearer picture of the budget status of each project. Currently the project level budget reports with year-to-date expenditures are of little value since the cash flows are not updated. It is impossible to tell whether a project is actually running over or under budget.

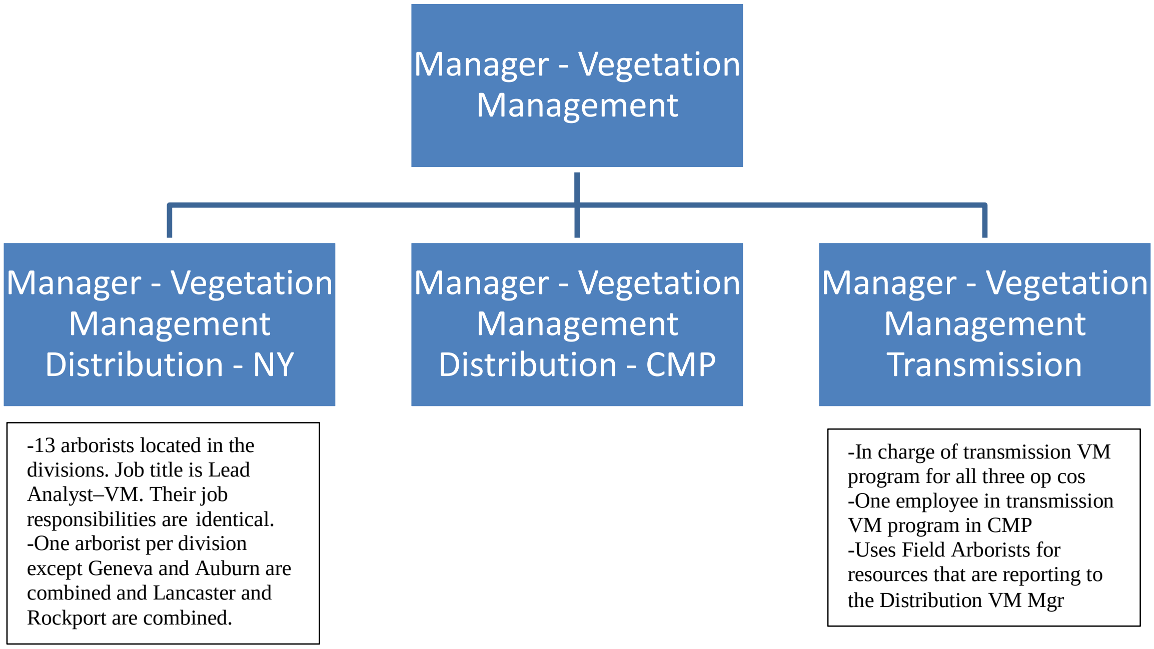
This is a procedural improvement that is not expected to have any negative cost impacts. Currently the budget reports with year-to-date expenditures are of little value since the cash flows are not updated. Providing factual year-to-date project expenditures is expected to improve the project management process.

D. Vegetation Management Program

1. Background

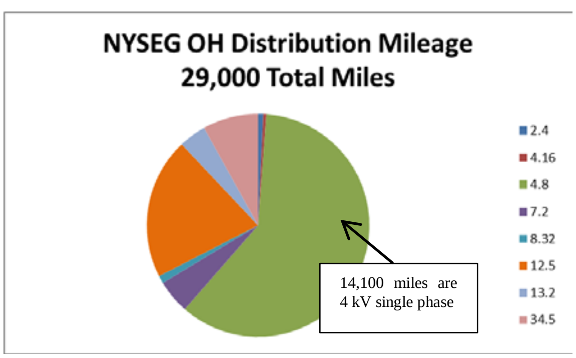
a. Organization and Overview

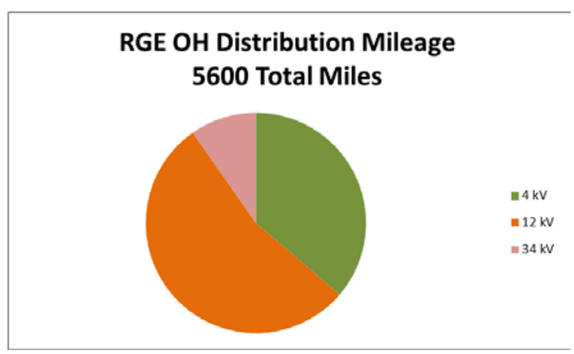
The organizational chart for the Vegetation Management Program is shown below.



The system line mileage which must be trimmed is shown in the tables and graphs below.

Overhead Transmission Line Mileage		
Total	NYSEG	RG&E
5,600	4,583	1,017





Contractors perform the vegetation trim work. Not all of the vegetation management contracts had been awarded for 2011 at the time of this audit. The estimated number of contractor crews that were to be used in 2011 is shown in the table below.

Estimated 2011 Tree Contractors			
	RG&E	NYSEG	Total Persons
Distribution	16- two person	86-two person	204
Transmission	six-five & six person	35- five & six person	205 - 246

b. Process and Program Overview

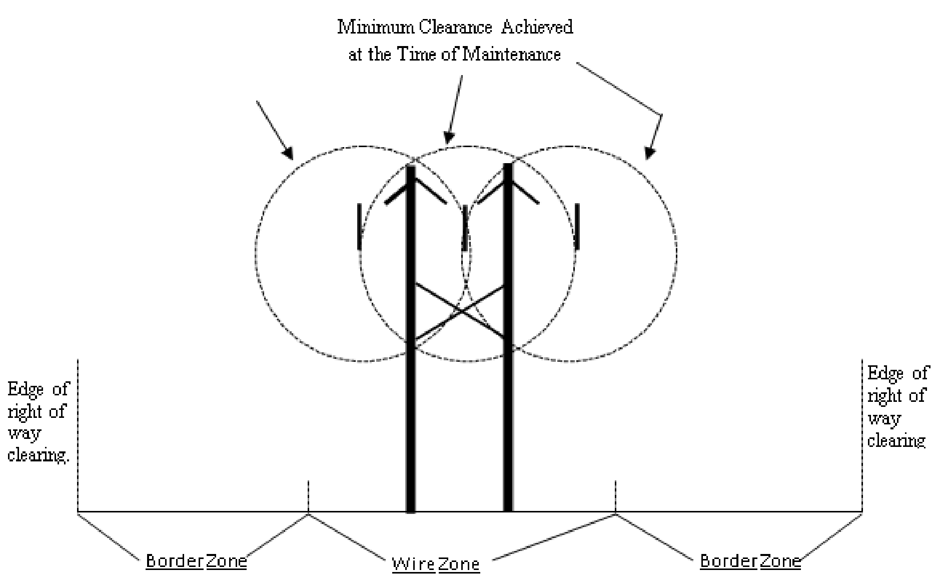
i. Transmission

All transmission work is planned and overseen by Company arborists. The tree work and herbicide applications are accomplished with the use of qualified contractors with close oversight by company personnel. The vegetation management team uses the "Long Range Right –Of-Way Management Plan for the NYSEG Electric Transmission System Transmission Vegetation Plan" (TVMP) as a guide for work planning, auditing, and includes specifications followed by the contractors. The vegetation management program also follows ANSI A300 (Part 7) -2006 IVM guidelines approved by the Tree Care Industry Association and International Society of Arboriculture Utility Arborist Association.

Each year, NYSEG and RG&E Arborists develop work plans for 16.6 percent of the transmission system which is on a six-year cycle. This year (2011) NYSEG is in the final year in the first cycle. RG&E has also implemented a six-year transmission vegetation maintenance cycle. This year (2011) RG&E is in the fifth year of the first cycle.

A lump sum bid process is used. Arborists select vegetation management techniques appropriate for the planned work. Supplier Services then send formal requests for quotations to all qualified bidders as determined by the company. Supplier Services manage the bidding process and review all bids with the vegetation management department. Work is awarded based on lowest pricing.

NYSEG arborists use a computerized inventory system (VMS, or Vegetation Management System) combined with field checks to identify treatment prescriptions and environmentally sensitive areas. NYSEG arborists prescribe the appropriate control techniques for the tree and brush conditions so that the most cost effective tool is used and the company can minimize the use of herbicides. The modified wire/border zone management approach encourages early successional plant communities which have wildlife benefits and at the same time help prevent the establishment of trees. These zones are shown in the diagram below.



The TVMP details the vegetation management methods which require the use of integrated vegetation management techniques. A variety of techniques are prescribed with the back bone tool being a low volume foliar herbicide application. Selected areas may be mowed to reduce stem densities. Environmentally sensitive areas will be cleared mechanically.

Annually the company arborists select hazard trees to be removed or identify rights-of-ways that require widening; the majority of this work is included in the lump sum project pricing. The annual aerial helicopter patrols and ground inspection reports are also used to identify hazard trees which provide information for the hot spot program allowing NYSEG to remove trees before a power outage occurs.

The bulk transmission system is managed aggressively, so that tree related power outages can be minimized on the backbone electric delivery network. The North American Electric Reliability Corporation (NERC) has developed national standards that transmission owners who manage trees on bulk electric transmission lines must follow. The NERC standard FAC 003 1 is a zero tolerance standard for any power outages resulting from trees within the active rights-of-ways. NERC audits each utility to ensure the program meets the FAC 003 1 requirements. NYSEG has used LiDar technology to survey the transmission lines and provides reports to field crews who removed trees that had the potential to violate company clearance zones.

ii. Distribution

The vegetation management team uses the “Specification for Distribution Right-Of-Way Vegetation Maintenance 2011 Lump Sum Mileage Work” as a guide for work planning and auditing, and includes specifications followed by the contractors. The vegetation management program requires that the contractors follow the ANSI A300 (Part 1) -2008 Pruning Revision of ANSI A300 (Part1)-2001 approved by the Tree Care Industry Association and International Society of Arboriculture Utility Arborist Association.

There are two work management methods used for distribution tree trimming. These are known as mileage work and hot spot work. Mileage work is defined as routine line clearance work that was generally completed on lump sum contracts. This program was designed to clear large sections of circuits to improve power quality and minimize tree caused power outages. Hot spot work is tree work that is identified throughout the year which required immediate attention to address safety, power quality concerns, or to prevent power outages. Hot spot work is done on a time and materials (cost plus) basis.

Each year, NYSEG and RG&E arborists develop mileage work plans for a portion of the distribution systems. Circuits are selected for work based on outage history, current tree conditions, year since last cleared and local considerations. Generally, NYSEG had been clearing the 3-phase 34.5 kV on a three year cycle, the 3-phase 15 kV on a five year cycle, and the 3-phase 5 kV on a seven year cycle. These lines are trimmed on a mileage basis. The single phase 15 kV and 4 kV lines were being trimmed on a hot spot basis.

Supplier Services, using the work plans developed by the vegetation management department, send formal requests for quotations to all qualified bidders as determined by the company.

Supplier Services manage the bidding process and review all bids with the vegetation management department. Work is awarded based on lowest pricing.

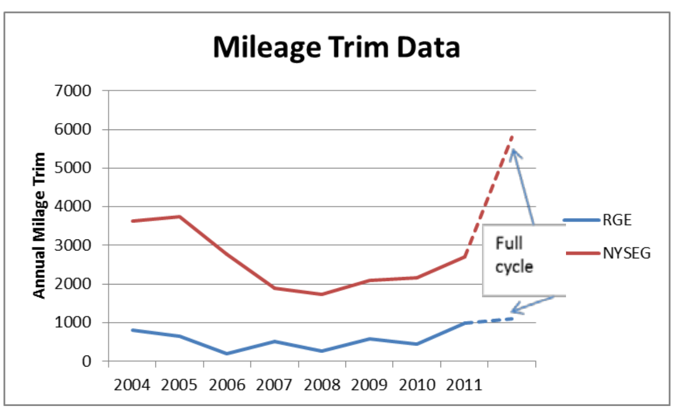
The standard clearing specifications are 10 feet above the pole top and 10 feet to the side of the conductors. Species capable of growing into the clearance zone are removed. Each year, the arborists schedule hot spot work which includes areas that were not included with planned lump sum contracts. These areas are cleared to improve power quality and minimize tree related power outages.

Most of the distribution lines are in the public way and built in close proximity to residential or municipal trees, making public relations a key factor in determining clearance specifications. The company arborists conduct start-up meetings with each vendor to review safety, work specifications, and environmental considerations. The company mails post cards to most abutters before the routine maintenance work is started. In addition the contractor is requested to notify landowners when major tree work is required. All state and federal regulations must be followed.

Periodically, the NYSEG and RG&E arborists identify hazard trees which are generally outside the clearing rights. Landowner permission is required before these trees are removed.

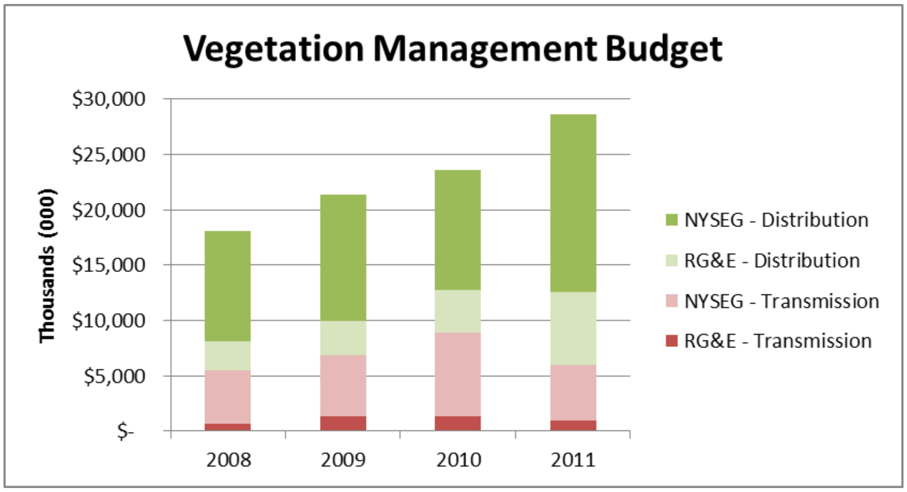
In 2011 RG&E started the first year of a five year cycle where approximately 20 percent of the distribution system will be cleared. In 2011 NYSEG expanded work into a higher percentage of single phase lines than previous years. Mileage trimming of some of the single phase lines is starting with the 2011 – 2013 cycles per the rate order. NYSEG intends to request funding for a five year line clearance cycle as part of the next rate case.

The historical distribution mileage trim data is shown in the graph below. In the past four years the mileage trim work at RG&E had quadrupled until they are now near a full cycle trim. The mileage trim rate at NYSEG has increased more slowly. They are not yet at the halfway point for mileage trim. Most of the lines lacking mileage trimming are among the 14,100 miles of 4 kV single phase lines.



iii. Budgets

The past actual budget data and 2011 planned budget data are shown in the graph below. The vegetation management budget has shown a steady increase over the years.

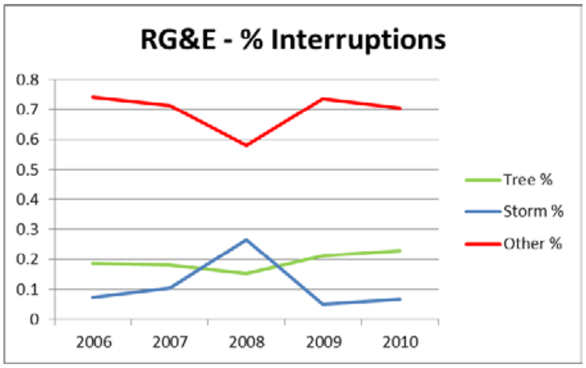


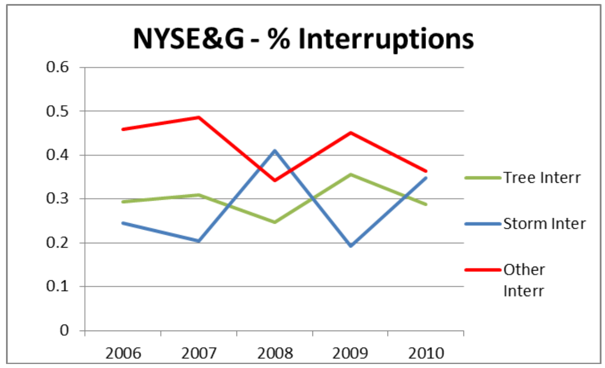
Both the NYSEG and RG&E distribution budgets were increased in 2011 in an effort to move to cyclic trimming for the systems. For 2011 RG&E is on a full five year trim cycle. NYSEG will be able to conduct more mileage trimming in 2011, but is still not funded at a level for full cycle trimming. The current rate order (2009) has the NYSEG budget increasing from $16M in 2011 to $20M in 2013. This is a $2M annual budget increase. The budget necessary for starting full cycle trimming at NYSEG is estimated to be $38.1M.

Both NYSEG and RG&E have mileage trimming goals in 2011. The minimum mileage trim goal for RG&E is 1,100 miles. The minimum mileage trim goal for NYSEG is 2,700 miles. Revenue penalties will occur if these minimum mileage trim goals are not met.

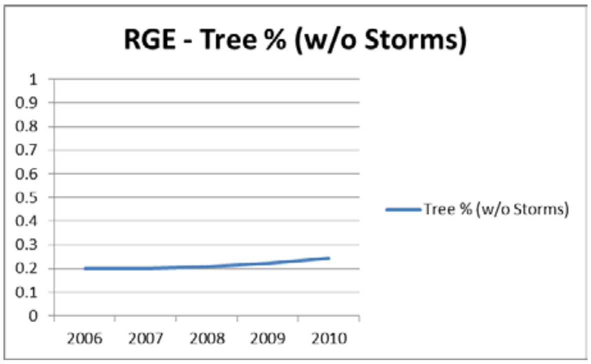
iv. Results

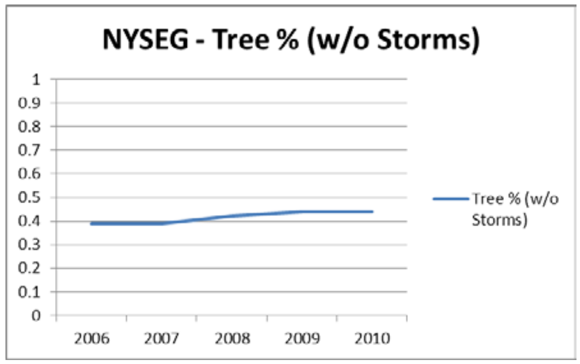
The goal of any vegetation management program is to keep the amount of tree-related outages at an acceptable level. The outages are tracked and logged individually during normal weather periods. During the major storm periods, tree outages account for 71 percent of all storm outages. The first two graphs below include all outage interruptions, including major storms. For RG&E, tree and storm outages accounted for 30 percent of all outages. For NYSEG, tree and storm outages accounted for 60 percent of all outages. The RG&E system has a much higher percentage of underground customers than the NYSEG system. Therefore, its tree related outages will be a lower percentage of the total number of outages.





The graphs below exclude major storms. The tree-related outages have been increasing steadily on both systems in relation to other types of outages.





2. Findings

a. Process for Contract Awards

A documented process should be in place for the selection and award of contracts for the vegetation management program.

The Iberdrola USA Procurement Services Policy Manual has strict rules for conducting the sealed bid process. This process requires both a technical evaluation of the bids and a commercial evaluation. Liberty reviewed the proposal evaluations and other documents. Overall the procurement service policies have been followed in for the selection and award of these contracts for both distribution and transmission.

The Request for Proposal for the 2011 vegetation management contracts (RFP #10595), dated November 15, 2010, had a contract procurement schedule that would have the contracts in place by January 2011. Contracts were not fully finalized in 2011 until June. The Vegetation Management goal for 2012 is to have the bid packages ready by July 1st of this year so tree contracts can be in place by Jan 1, 2012. The contracts include lump sum bids for mileage work that contain $3,000 per day per circuit penalties for work not completed by December 31st. They also include the prices to be used (time and materials) for any hot spot work.

The contract process for distribution is not yet fully based on cyclic trimming schedules. It includes a high volume of hot spot work. Hot spot work is inefficient from both a cost and a reliability standpoint. The benefits of a cycle-trim program have been well settled. Reports from the early 1990s have recommended implementation of cycle-trim programs. A NYSEG Transmission and Distribution O&M Benchmarking Study dated November 1993 report recommended cyclic trimming schedules. A "PACE OPS '95" report also recommends a cycle line clearance program. These studies support NYSEG adopting a cyclic line clearance program for distribution operations.

In its last rate case, NYSEG submitted testimony in support of a distribution cycle line clearance program, which included the points listed below. NYSEG intends to request funding for a five year line clearance cycle as part of the next rate case.

- Establishing a full cycle line clearance program for all distribution circuits would support continued reliability performance and in the long run be most cost-effective.
- Lines on cleared ROW are less likely to sustain interruptions due to tree contact, and it follows that clearing more ROW on a periodic basis will maintain or improve reliability.
- Cycle clearing ensures that ROW boundaries are well-established and maintained on a regular schedule, providing consistent visibility and accessibility to inspection and repair crews. This allows for quicker identification and correction of problems and facilitates preventive line maintenance.
- Cycle clearing also ensures periodic identification and removal of danger trees along the ROW edge.

Cycle clearing also enhances public safety by minimizing the risk that vegetation will become energized, and lessens the system-wide potential for human contact with energized conductors. The reduction in vegetation size, density and proximity to energized conductors that can be achieved with periodic, scheduled clearing, and the reduction in handling costs for the large trees removed during the first cycle can mitigate the cost of subsequent clearing cycles. Further, a comprehensive cycle program would allow for even more efficient planning and contracting of clearing work, reducing per-mile maintenance costs. Cyclical line clearance also helps improve customer satisfaction. Customers are more amenable to frequent cutting of small limbs and trees, and generally view this as acceptable.

Without cyclic trimming, the hot spot costs are projected to increase in the near future. A September 2010 Distribution System Vegetation Workload Study found a significant amount of ROW growth (brush) 6 to 18 feet tall throughout the system. The study cited the following warning:

"As brush matures over about 6 feet in height, maintenance costs start to increase significantly and maintenance options diminish. Allowing brush stems to mature will increase the likelihood that this vegetation will become part of the future trimming program rather than be maintained as brush acreage. This may have a significant impact on future tree trimming costs." It went on to additionally cite "….failure to maintain or control the brush population will result in much higher tree trimming costs in future years." The study also made the following observation about trees growing close to energized conductors. "Of significant importance is the 47 percent of the trees on the Iberdrola USA system that are within 4 feet of the conductors and have the potential to make line contact within two growing seasons. This could be a significant cost driver in future maintenance costs."

The cost of trimming a mile of line is directly related to the length of the trim cycle. Historical averages are shown in the table below. Note that these costs are based on circuit miles, not trim miles. Circuit miles are the total line miles in a circuit. Trim miles are the wooded portions only of the circuits.

Voltage Class	35 kV	Non-35 kV 3 PH	Non-35 kV 1 PH
Avg Cost per Mile	$2,500	$4,000	$6,500
Avg Trim Cycle	3	5-7	N/A

The cost of bids for recent trimming of single phase lines, which are the ones overgrown, is trending upward. Single phase lines have been averaging $6,500 per mile to trim. Some recent 2011 bid data for 150 miles of line was averaging $11,300 per mile to trim.

The business case for going to cyclic tree trimming programs is most often calculated by a Net Present Value (NPV) study comparing the cyclic options to the present trimming practices. These studies include the cost of tree trimming and the costs associated with tree outages. Iberdrola has not completed a NPV study for NYSEG. In conjunction with NYSEG, Liberty modeled a NPV study on the benefits of cyclic trimming. Both historical per mile trim rates and recent bid data was modeled. A total of four scenarios were modeled. These scenarios were:

1. Base Case – Hold annual budget to the current level of service - $20M with an annual escalation factor.
2. Plus $2M – Continue to increase budget $2M each year until a full cycle trim is established.
3. Plus $4M – Increase budget $4 M each year until a full cycle trim is established.
4. 5 Year cycle – Increase budget to start a full 5 year cycle in 2014.

These savings indicated it was economical to implement cyclic trimming. 15 year NPV savings range from $17M to $83M, depending on the implementation plan and trim rates costs.

b. Contract Provisions for Work Management

Contracts utilized for the vegetation management program’s physical work should include provisions that facilitate the utility’s management of the work.

i. Distribution

There are a number of performance measure provisions in the distribution vegetation management contracts. There are provisions on customer complaints, crew caused outages and safety. There is also a provision that any rework will be at the contractors’ expense, and that rework will be no more than 10 percent of the contracted mileage.

The main performance measure is a provision that work will be completed before the end of the year or penalties of $3,000 per circuit per day will be assessed. Under the lump sum contract the contractor is in control of the trimming schedule for each circuit. They are also in control of the amount of progress they make each month. Therefore, this penalty provision is critical in ensuring work is completed on schedule.

All lump sum mileage work is paid on a circuit basis. When 50 percent of the circuit is complete and rework is finished then 50 percent of the cost of the circuit will be paid. When the circuit is 100 percent complete and rework is complete the final payment will be made. The contractor can elect to submit either 50 or 100 percent payment for a circuit. Time and material or construction clearing work is invoiced weekly.

In 2010 Environmental Consultants, Inc. was hired to complete a vegetation workload survey. This information is a valuable bid resource. It is used to prepare plans for cycle work as well as provide contractors tree density information to assist in the preparation of bids.

ii. Transmission

The contractor is required to submit a work schedule prior to the start of the annual work. They also must provide notification to the Company regarding starting and stopping of work each day.

The contracts require that the contractors conduct a field survey during the growing season following vegetation management work and submit a written report before August 1 the year after treatment. The contract requires 100 percent kill or removal of non-desirable vegetation within the wire zone and 95 percent control in the edge zone. Any work that did not meet specifications will be completed by the contractor at no additional cost to the Company.

Upon completion of this review and any necessary correction to the work, the contractor shall submit a Contractor Work Guarantee Form certifying that items have been completed and that the job is submitted for final acceptance by the Company. The contractor shall provide the Contractor Work Guarantee Form to the Company Representative no later than August 1 during the year following initial treatment.

The same payment provisions in the distribution contracts for 50 or 100 percent of the transmission circuit or work unit apply.

c. Performance Monitoring and Minimizing Program Costs

Performance of various contractors should be compared regularly with the results used to minimize program costs on a continuing basis.

The annual lump sum bid process does a good of comparing contractors on a regular basis. Every year the mileage work portion is bid. A direct measure of costs from year to year or contractor to contractor can be made. However, the lump sum bid process does nothing to minimize the program costs on an ongoing basis. Contractor workshops exploring cost reduction opportunities were conducted in 2010.

The primary factors in minimizing the ongoing costs of a vegetation management program are:

- Use of industry standard pruning practices such as directional pruning
- Good pre-established clearing limits that allow for the type of line, expected growth rate and length of cycle
- Proper use of herbicides to maintain or extend pruning cycles
- Consistent programs of cyclic clearing over a long term

Liberty has ranked the vegetation management programs for transmission and distribution. They are ranked against these factors in the table below.

Factor	Transmission	Distribution
Pruning practices	Good	Good
Clearing limits	Good	Fair
Herbicide use	Good	None (Poor)
Consistent cycle programs	Good	Poor, but improving

The distribution program cycle has already been discussed in section 1 above. Another issue with the distribution program is the use of tree growth regulators, or herbicides, to extend the pruning cycles. Herbicides must be used in conjunction with regular trimming cycles. The benefits of applying herbicides as a component of a utility integrated vegetation program are well documented in the utility industry. The 2010 McKinsey report, McKinsey Spin Off reports, and Vegetation Management Handbook also support and recommend for NYSEG and RG&E the use of herbicides in the distribution program. Herbicides have been a standard part of the Central Maine Power Company distribution line clearance program for many years. Study on a transmission segment in Maine showed a 60 percent% drop in the costs of mechanical trimming from the use of herbicides.

Herbicide use is included in the distribution tree trimming specifications but is not included in the contracts. Iberdrola estimated a Net Present Value Savings (15 year period) of $1.52M from the use of herbicides based on the present number of circuit miles being trimmed. With full cyclic trimming the estimated Net Present Value Savings are $6.7M. For the 2012 bids they will investigate adding some herbicide work to the specifications. The bid packages out have a provision for adding CST (cut surface treatment) to the specifications. The CST treatment involves a tree growth regulator applied to cut stumps to prevent shoot regrowth.

d. Adequate Number of Supervisors

An adequate number of trained utility supervisors/contract managers should be assigned to the oversight of contractors.

In 2006 a vegetation manager was hired who was responsible for NYSEG transmission and distribution work. In 2009 a manager for transmission vegetation management was hired. Prior to 2010 the number of field arborists at NYSEG varied and work was completed using a combination of in-house NYSEG arborists, contractors, or line department personnel. In 2010 Iberdrola USA determined that it was a best utility practice to hire in-house staff to manage the vegetation management program. Each division has a utility arborist based in the local offices and is responsible for both distribution and transmission vegetation management work. Auburn and Geneva are managed with one arborist, and Lancaster and Lockport are also managed with one arborist.

RG&E employed one arborist until 2008 when a second arborist was hired. Both arborists reported to the Distribution Vegetation Management Manager in 2010. The vegetation managers took over direct responsibility for the RG&E programs.

The net staff now consists of the following:

- One Manager – Vegetation Management
- One Manager – Vegetation Management Transmission
  - One report: Lead Analyst – Vegetation Management
- One Manager – Vegetation Management Distribution
  - 13 reports: Lead Analyst – Vegetation Management

Each of the field arborists has a training plan included in their annual performance expectations.

e. Oversight and Audit

There should be adequate oversight and audit of contractor management and payments.

i. Transmission

Vegetation management is performed using an in-house application called the Vegetation Management System (VMS). The arborist conducts a detailed vegetation inventory of each right-of-way, determining the method of treatment to be employed on each site. All pertinent information concerning the ROW width, special conditions and restrictions are reviewed by the arborist and factored into the treatment design. The inventory information is recorded in the geographic information system (GIS) based vegetation management system (VMS) that ties all of the information to a map location. VMS maps, showing the management units, are provided to the contractor and serve as instructions for completing the vegetation maintenance work. The data for completed work is entered into the VMS system and includes the date the work was performed, type of treatment, herbicide formulation and quantity applied if used. Any changes to the original inventory, contractor name or applicator are recorded. This provides a permanent record of the work performed.

Before the work is started Iberdrola and contractor supervision meet to review specifications, timetables, and work plans. The contracts require that the contractors conduct a field survey during the growing season following vegetation management work and submit a written report before August 1 the year after treatment. The contract requires 100 percent kill or removal of non-desirable vegetation within the wire zone and 95 percent control in the edge zone. Any work that did not meet specifications will be completed by the contractor at no additional cost to the Company. In addition the Company arborists also conduct field audits of completed work to ensure that the contract specifications are met. The contractors submit monthly progress reports. The contractor will be penalized for planned work which is not completed by the end of the calendar year.

The Company arborists conduct start-up meetings with each vendor to review safety, work specifications, and environmental considerations. Contractors must select herbicides off the list provided by NYSEG. The contract requires each contractor to notify abutters in advance of herbicide applications. All state and federal regulations must be followed. Starting in 2011, the company arborists periodically visit crews to verify that appropriate work practices are being followed. The arborists fill out a crew analysis form to document to visit and confirm that approved practices are followed.

NYSEG developed a Quality Accordance Plan, also applicable to RG&E in 2010 which details the audit process. Historically, the Company arborists spot check vegetation management work once completed by the contractors. The transmission manager also conducts spot audits to check that the quality of work meets Company specifications including environmental guidelines. These field checks are documented on form, "Vegetation Management Audit of NYSEG's 69kV and above Transmission System." The contractor is required to certify all worked completed in the previous year meets NYSEG /RG&E specifications before August 1st the year after treatment work is completed. Any work not meeting specifications must be corrected at contractor's expense.

All invoices are approved by the arborists assigned to the Division where the work was completed. Invoices and time sheets are reviewed and compared. Approvals are forwarded to accounts payable and checks are sent to vendors. Arborists will hold payments until work is completed to specifications.

All worked is entered in to an electronic data base referred to as the Vegetation Management System (VMS). Once the data is entered, reports are generated that list the treatment type, number of acres treated, and costs of each type of work. This data is used for NYPSC regulatory reporting and planning future work. This system is used to create work plans for upcoming work including budget estimating and data included in contractor request for quotation packages.

ii. Distribution

Starting in 2011, the Company arborists periodically visit crews to verify that appropriate work practices are being followed. The arborists fill out a crew analysis form to document to visit and confirm that approved practices are followed.

All invoices are approved by the arborists assigned to the Division where the work was completed. Invoices and time sheets are reviewed and compared. Approvals are forwarded to accounts payable and checks are sent to vendors. Arborists will hold payments until work is completed to specifications. Currently each division arborist tracks completed work and reports periodic progress to the Distribution Manager.

RG&E did not plan or track work by voltage class. Also, the work or cost tracked by phase is not available. RG&E did not track hot spot miles completed. The data tracking at NYSEG was more detailed. Overall, the paper tracking procedures need to be upgraded to keep up with the modern day data demands.

A new electronic recording keeping system (Field Data Collection Project) is under development so that all distribution work can be tracked in a uniform manner. The project was recommended by McKinsey Consulting in their 2010 study. This project requires the purchase of Motorola MC-75 handheld computers (275 for NYSEG and 50 for RG&E) and associated hardware. Distribution vegetation management data will be collected in the field and loaded directly into a central data base. The units will contain the distribution work locations so that contractors will know that they are working in the correct locations and weekly progress can be tracked. A centralized data base will contain all customer notification contact information.

The new units will allow Iberdrola to meet the vegetation management (VM) tracking requirements recently identified in the NY rate case. The approved case requires that Iberdrola track and annually report the number of miles cleared, miles of each voltage class cleared and the cost to complete the work.

The new units will allow for a robust system to track contractor productivity, work progress, and costs. This will provide valuable information for the management team and supply chain when bidding future work. The cost estimate to implement this program is $981,000 for NYSEG and $287,000 for RG&E.

f. Similar Measures for Internal Contractors

Similar measures should exist for internally performed vegetation management activities.

There are presently no internal tree crews at either company. This is in-line with industry practices.

3. Conclusions

20. A documented process is in place for the selection and award of contracts for the vegetation management program, but the delay in marshaling resources and the lack of a more structured cycle-basis are gaps. (*Recommendation #1 and #2*)

A documented bid process prescribed in detail by the Procurement Services Policy Manual is in place and being followed.

The planned procurement schedule for vegetation management was not followed in 2011. Contracts were not fully finalized until well past June 1. This same procurement schedule delay has occurred in prior years. The lack of time for actual trimming work is eventually reflected in the contractor's lump sum bid price. Due to the late penalties the contractors take a greater risk in completing the work. The time squeeze will also eventually affect the quality of the work (removal of dead overhanging limbs or hazard trees).

Many large utilities use the annual lump sum bid process. It is a valid process if properly executed. There are two possible approaches to improve the timely completion of the yearly contract process. One approach is already being attempted. The lump sum bids can be in place at the beginning of the year through proper planning. This approach was unsuccessful in past years. Another approach is to request multi-year bids rather conducting a new bid process each year. The multi-year bids would have the contracts in place on an ongoing basis. A multi-year bid could also be more economical. A contractor could be willing to have a lower price for the assurance of additional work.

Single phase 12 kV and all 4 kV lines have been hotspot trimmed only. Starting in 2011 RG&E is budgeted for full cyclic trimming. This does not mean that RG&E is now on a full trim cycle. It just means that they are starting on a five year process to get on one. Twenty percent of the lines that were being hotspot trimmed will be cycle trimmed in 2011. Hot spot trimming for portions of the remaining line sections will still be necessary until 2016. Tree outages on those line sections will remain high and still be increasing until 2016. At that time the lines will have all been recleared and RG&E will indeed be on a five year trim cycle. Lines being trimmed will therefore have five years vegetation growth to trim rather than over 25 years of growth. NYSEG is not on a trim cycle for these types of lines. The existing tree growth averages 20 years and is reported to be growing between the circuit conductors. Even if NYSEG were to start on full cycle trimming this year, there would be five more years of vegetation growth before all of the lines would be recleared. The NYSEG system should be budgeted for full cyclic trimming.

21. Contracts utilized for the vegetation management program's physical work include provisions that facilitate the utility's management of the work.

Overall, Liberty finds that the contracts have provisions in place that facilitate the management of the work. These provisions allow Iberdrola to monitor the progress and quality of the work.

The contracts in place are lump sum contracts. Under the lump sum contract the contractor is in control of the clearing schedule for each circuit. All lump sum mileage work is paid on a circuit basis. This enables Iberdrola to monitor the work progress.

The transmission circuits are on a cyclic trim schedule. The contractor is required to submit a work schedule prior to the start of the annual work. They also must provide notification to the Company regarding starting and stopping of work each day. In addition, the contracts require that the contractors conduct a field survey during the growing season following vegetation management work and submit a written report before August 1 the year after treatment.

The distribution circuits have penalty provisions in the contract if the work is not completed by the end of the year. The performance measure requires that work will be completed before the end of the year or penalties of $3,000 per circuit per day will be assessed.

22. Performance of various contractors is compared regularly with the results used to minimize program costs on a continuing basis. (*Recommendation #3*)

The lump sum bid process does a good job of comparing contractors on a regular basis. However, it does nothing to minimize costs on an ongoing basis. One primary factor in minimizing ongoing trim costs is the proper use of tree growth regulators (herbicides) to maintain or extend pruning cycles. Herbicides should be implemented in the distribution vegetation management program. The use of herbicides in the distribution vegetation management program is estimated to provide net present value savings.

23. An adequate number of trained utility supervisors /contract managers is assigned to the oversight of contractors.

Liberty finds that there are adequate numbers of vegetation managers and staff in place. There is an overall Manager of vegetation management, a manager over distribution vegetation management in NY, and a transmission manger of vegetation management. Each division has a utility arborist based in the local offices and is responsible for both distribution and transmission vegetation management of the contractor work.

24. There is adequate oversight and audit of contractor management and payments.

Liberty finds that there is adequate oversight and monitoring of the contractors. Processes, procedures and systems are in place for contractor management. A quality audit process is in place. A payment process based on circuit increments is in place.

Transmission vegetation management is performed using an in house application called the Vegetation Management System (VMS). This contains the vegetation data and the work plans. The documentation of the completed work is entered into the VMS system.

Distribution work is currently being managed through a paper reporting process. A new electronic recording keeping system (Field Data Collection Project) is under development so that all distribution work can be tracked in a uniform manner. This system has been successfully implemented at CMP. This system will greatly improve the work tracking capability and reports.

4. Recommendations

6. Put vegetation management contracts in place by January 1 of the contract year. *(Conclusion #20)*

The vegetation management planning process needs to be improved. Contracts for the current year should be in place at the beginning of the year. The 2011 contracts were not in place until mid-year. This reduces the timeframe the contractor has available for trimming and indirectly increases their bid cost.

Due to the last issuance of contracts in 2011, the amount of time for the contractor to do the work has been cut almost in half. The lack of time for actual trimming work is eventually reflected in the contractor's lump sum bid price. Due to the late penalties the contractors take a greater risk in completing the work. The time squeeze will also eventually affect the quality of the work (removal of dead overhanging limbs or hazard trees).

There should not be any incremental costs for implementing this recommendation. It is noted that the 2012 bid process appears to be much further along than the 2011 process.

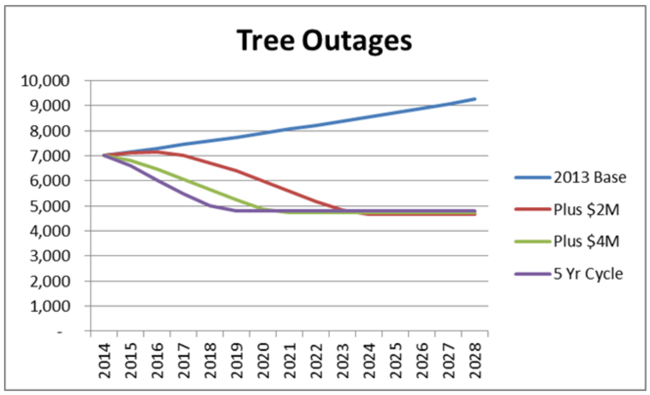
7. Move to a five year trim cycle on all circuits. *(Conclusion #20)*

The PSC and Iberdrola have been moving closer towards establishing full trim cycles for both RG&E and NYSEG in recent years. The single phase rural 4 kV lines, which compromise almost 50 percent of the NYSEG system, are reported to be overgrown from the ground to the conductors. As this tree growth continues unchecked, the tree-related outages and the costs of hotspot trimming will increase significantly. NYSEG should move to a full five year trim cycle for these lines.

The long range benefits of cycle trimming are well known. As lines are trimmed more frequently the cost per mile to trim the line drops. For general forested conditions, the industry has recognized 5 to 7 years as the most economical trim cycle periods. The NPV studies indicated that the option of increasing the vegetation budget $2M annually (Plus $2M plan) until a five year cycle was achieved would have a 15 year NPV savings of $17.5M. Increasing the vegetation budget at a faster rate (Plus $4M plan) would have a NPV savings of $15.1M.

The drawback to implementing full cycle trimming is the cost of removing the existing burden of vegetation. The options of increasing the vegetation budget gradually rather than all at once help ease the rate burden on customers by phasing in the cost increases.

The reliability improvements from cyclic trimming were also modeled and are shown in the graph below. It is estimated that five year cyclic trimming would reduce the number of tree outages by 38% from their present day levels. The main advantage of the Plus $4M plan is more outages are avoided and the risk avoidance of large major storm impacts.



8. Achieve the benefits of using herbicides in the distribution vegetation management program. *(Conclusion #22)*

Herbicides should be implemented in the distribution vegetation management program. The use of herbicides in the distribution vegetation management program is estimated to have a net annual savings of $1.52M. This recommendation is a part of the vegetation management long range strategic plan. Starting in 2012, the bid packages have a provision for adding CST (cut surface treatment) to the specifications. The CST treatment involves a tree growth regulator applied to cut stumps to prevent shoot regrowth.

The current distribution vegetation management contracts do not include the use of any herbicide treatments. Herbicides, or tree growth regulators, slow or control the vegetation growth process. They are proven to reduce vegetation management costs. Some proper applications have reduced future trim costs by 30%. The use of herbicides for distribution vegetation management is a recognized industry best practice. It is estimated that 50% of the NYSEG lines and 30% of the RG&E lines could benefit from the use of herbicides.

Herbicides have been used in the transmission program for over six years. Herbicide usage has been in the distribution vegetation specifications, but has not been included in the contracts. The right-of-way should be on a cyclic trim before herbicide usage is effective. As more miles of lines are added to cyclic trim schedules, herbicide usage is an addition to the program that would reduce the future trim costs by slowing the rate of vegetation growth.

E. Energy Efficiency Program

1. Background

a. Program Origination

On June 23, 2008, the Public Service Commission established the New York Energy Efficiency Portfolio Standard (EEPS) proceeding. The Commission established interim targets and funding through the year 2011 as part of a statewide program to reduce New Yorkers' electricity usage 15 percent of forecast levels by the year 2015, with comparable results in natural gas conservation. The State's utilities were required to file energy efficiency programs, and the New York State Energy Research and Development Authority (NYSERDA), as well as independent parties, were invited to submit energy efficiency program proposals for Commission approval.

Since June 2009 the Commission has approved over 90 electric and gas energy efficiency programs, along with rules to guide implementation and measure results, through a series of orders. The Commission has in many instances approved specific rebate/incentive levels for specific measures on a program specific basis. For custom measures, the Commission has not approved specific rebate/incentive levels. For "Fast Track" residential electric and gas HVAC appliance rebate programs, the Commission has mandated the use of uniform rebate levels on a statewide basis. Utilities are allowed to make adjustments in energy efficiency program or measure rebate/incentive levels of up to plus or minus 20 percent of Commission-approved levels.

b. Overview of Iberdrola Programs

NYSEG and RG&E initially set up the following energy efficiency programs:

1. Residential Gas HVAC Rebate Program
2. Commercial & Industrial Prescriptive Rebate Program
3. Commercial & Industrial Custom Rebate Program
4. Multi-Family Rebate Program
5. Small Business Direct Install Program
6. Block Bidding Program
7. Refrigerator & Freezer Recycling Program
8. Home Energy Reports Program.

Descriptions of the program areas are shown below.

Fuel	OPCO	Program	Description
Gas	NYSEG	Residential Gas HVAC Rebate	The Residential Gas HVAC Rebate Program offers residential natural gas customers rebates for specific energy efficient equipment. Eligible equipment includes: high efficiency natural gas furnaces, water boilers, steam boilers, boiler reset controls, indirect water heaters, programmable thermostats and duct sealing.
Gas	RG&E	Residential Gas HVAC Rebate	
Electric & Gas	NYSEG	Commercial & Industrial Prescriptive	Electric - Pre-determined rebates for specific electric measures which include lighting, controls and Variable Frequency Drives, unitary HVAC equipment and chillers

Fuel	OPCO	Program	Description
		Rebate	in non-residential applications.
Electric & Gas	RG&E	Commercial & Industrial Prescriptive Rebate	Gas - Pre-determined rebates for specific gas measures which include installation of condensing boilers, hydronic boilers, furnaces, steam boilers, thermostats, and controls in non-residential applications.
Electric & Gas	NYSEG	Commercial & Industrial Custom Rebate	Electric - Site specific cost-effective electric savings measures for retrofit opportunities in non-residential applications. Gas - Site specific cost-effective gas savings measures for retrofit opportunities in non-residential applications.
Electric & Gas	RG&E	Commercial & Industrial Custom Rebate	
Electric	NYSEG	Multi-family	This program provides equipment replacement and rebates designed to reduce electricity use in 5 – 50 unit apartment and condominium complexes. Free installation of compact fluorescent bulbs (CFLs) in up to six fixtures in dwelling units. Incentives up to 50 percent of the cost of common area lighting upgrades.
Electric	RG&E	Multi-family	
Electric	NYSEG	Small Business Direct Install	Focused on the needs of business customers with demand of less than 100 kilowatts (kw). Eligible businesses will receive free energy assessments and 70% of the cost of recommended lighting upgrades., which include high efficiency lamps and ballasts, CFL's, LED's and LED exit signs.
Electric	RG&E	Small Business Direct Install	
Electric	NYSEG	Block Bidding	Provides competitively bid funding to groups of customers, in "packages" put together by a bid aggregator, to incent energy efficiency programs for the non-residential electric customers.
Electric	RG&E	Block Bidding	
Electric	NYSEG	Refrigerator Freezer Recycling	This program was approved by the Public Service Commission in January 2011, and the Companies are actively engaged in start-up activities, including final selection of an implementation contractor. The program will be an appliance rebate bounty program that will provide customers with $30 each for the removal and recycling of up to two functioning, inefficient second refrigerators and freezers. The Companies anticipated launching the program on approximately on May 1, 2011.
Electric	RG&E	Refrigerator Freezer Recycling	
Electric & Gas	NYSEG	Home Energy Reports	This program was approved by the New York State Public Service Commission on 1/25/2011. An implementation contractor has not yet been selected for this program. The Companies are currently discussing the timing of start-up of this program with Department of Public Service Staff (DPS Staff), and expected to file additional information regarding the program later in
Electric & Gas	RG&E	Home Energy Reports	

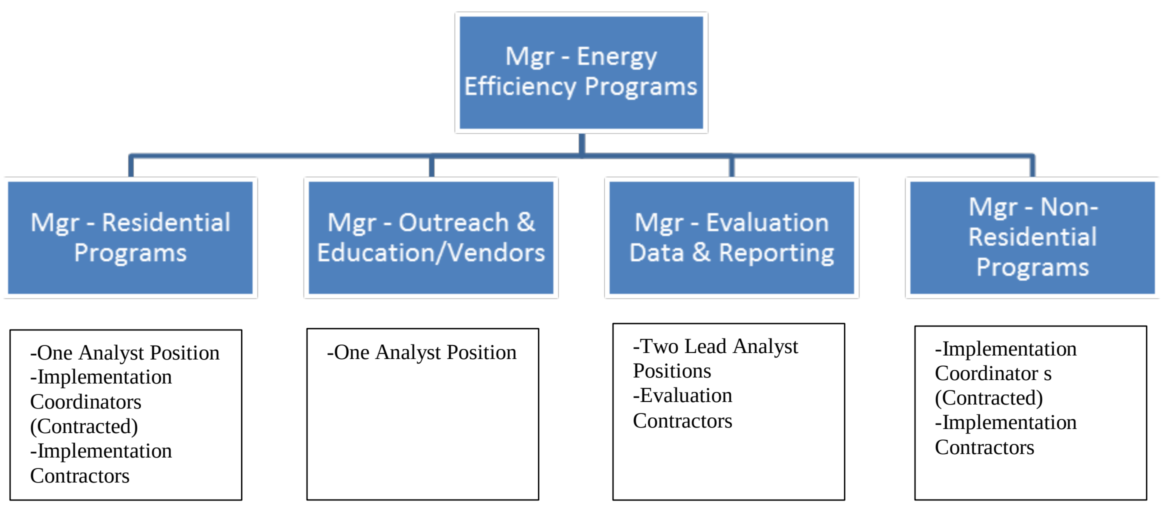
Fuel	OPCO	Program	Description
			April, 2011. NYSEG and RG&E will provide participating customers with customized reports that compare their electricity and natural gas usage with that of similarly situated neighbors. The reports will contain energy efficiency tips and information on available energy efficiency programs.

During the course of this audit, the Home Energy Reports program was withdrawn by Iberdrola. Also, on May 24, 2011, the 100 kwd limit in the non-residential programs was eliminated by the PSC.

c. Organization

The organizational structure of program management to date has consisted mainly of contractor personnel for implementation coordination with oversight by company personnel. The Companies have recently (February - April 2011) created an in-house energy efficiency team. One of the first strategic plans is to transition much of the general administration and planning work previously accomplished with outside consultants to these internal resources. This is expected to occur over the next six to nine months. The transitioned work will include program planning, budget planning, new program planning, technical evaluation, benefit-cost testing and other general administrative work.

The current organizational chart is shown below.



The key players are the Program Managers, Program Implementation Coordinators and Program Implementation Contractors. Their job responsibilities are shown below.

Program Managers – consists of two internal Company employees

- Program Design, Modifications, and Reporting
- Regulatory Relationship
- Program Performance (operations, monitoring and corrective actions)

- Program Budget
- Vendor and Implementation Coordinator Management
- Internal Coordination and Collaboration
- Procurement Collaboration
- Outreach & Education Collaboration

Program Implementation Coordinators – consists of 4 AEG contractor employees

- Daily interaction with Program Contractor
- Assists with Program Design, Modifications, and Reporting
- Assists with Program Performance (operations, monitoring and corrective actions)
- Assists with Vendor Management
- Assists with Other Collaborative Activities

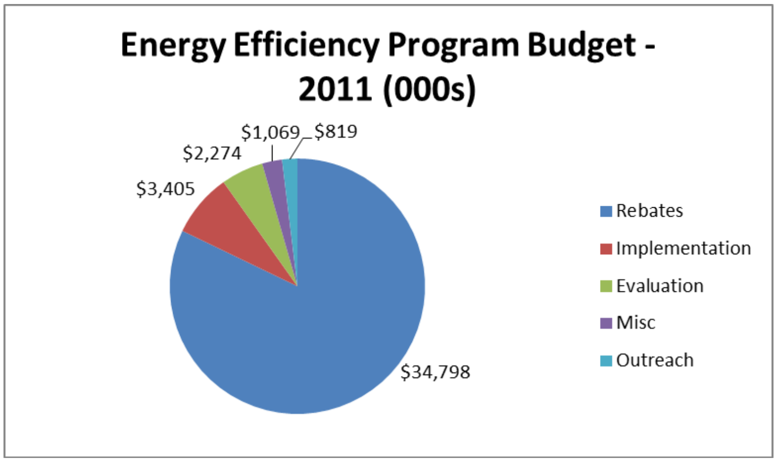
Program Implementation Contractor – consists of contractor employees in 6 different companies

- Responsible for carrying out day-to-day program activities per contract
- Responsible for performance and reporting per contract
- Responsible for Collaborating on Program Activities When Requested
- Responsible for the hiring and performance of any sub-contractors.

The Marketing & Sales group plays a big part in the customer promotion work for the energy efficiency programs. The sales force consists of nine Lead Analysts – Marketing & Sales and eight Lead Analysts – Key Account Managers. Everyone has 40% of their performance expectations devoted to promoting the C&I Rebate Program (both custom and prescriptive). They do a lot of outreach and have quarterly goals on events. They interact with the rebate contractor ICF. They provide customer help with the on-line self-assessment tools, but do not do any full blown audits. They have no involvement with any of the other programs.

d. Budget

The 2011 budget for these programs is shown in the graph below. The total 2011 budget is $42.3M. This includes about $5M of unspent funds from 2010. The rate order included funding for the 2010 thru 2011 period. Five percent of the budget was mandated for program evaluation. These budget figures do not include any Company labor as it is included in the base rate. Rebates to the customer, including any service incentive work done on their property, compromise 82 percent of the budget. The miscellaneous category includes incremental employee items that are not in the base rate (employee travel, dues and memberships, training), contractor labor for overall program planning, and shared licensing.



2. Findings

a. Documented Process for Contracts

A documented process should be in place for the selection and award of contracts for the energy efficiency programs.

The contractor bid process is strictly defined in the Iberdrola USA Procurement Services Policy Manual. The process is administered by Strategic Sourcing group. This process would apply to all contractors including tree, line, gas and engineering. All purchases over $15k must be a competitive bid. All projects over $100k must be a sealed bid.

Strategic Sourcing receives information on the scope and need for an RFP from the business end. Strategic Sourcing then comes generates the RFP. They maintain a list of approved suppliers and approved bidder lists. They then allow four weeks for the RFP to be priced by the bidders. After that there is a separate commercial evaluation and a technical evaluation done on each bid.

There are eight primary contractors used in the energy efficiency program. Liberty reviewed all of the commercial and technical evaluations of these bids. The Iberdrola corporate RFP process was followed for these bids. All bids had at least two bidders. Some had four or more. Liberty found the commercial and technical evaluations were thorough. The technical evaluations had an identified evaluation team that provided input leading to a weighted technical evaluation score. Some of the evaluation items included employee expertise, company experience, proposal quality, management and start-up fees, etc. In several cases the low bidder was not chosen due to the technical evaluation score, but in no case was the chosen bidder very far from the lowest bid amount.

b. Project Managers and Process in Place

All energy efficiency programs should have a Project Manager and a documented PM process in place controlling costs, schedules and quality.

The overall program goal is to promote energy conservation in an economical manner for both the utility and the customer. Program performance is generally measured on a dollar per MWh saved or dollar per dekatherm saved over a given time frame. The entire portfolio standard has an objective horizon of achieving 15 percent energy savings (over baseline energy consumption forecast from 2008 forward) by 2015.

Each program was allocated an energy savings goal in the original 2007 Order of the Commission (Case 07-M-0548). The current goals are being measured over a 2010-2011 combined period. There are negative utility financial incentives in place if these goals are not met. As of mid-2011 it is too early to report final goal results. However, we can look at current trends. The Residential Gas HVAC Program, Multi-family Program and the Block Bidding Program are meeting or exceeding their goals. The Small Business Direct Install Program and all of the four Commercial & Industrial rebate programs are lagging behind. The Small Business Direct Install Program has a continued lower than anticipated participation rate. This is attributed largely to the current difficult market conditions for small businesses. Some program changes being done are increasing numbers of the contractor's field Energy Service Representatives (ESRs) and additional marketing activities. The 100 kW demand restriction for the electric portion of the C&I Custom Rebate Program has been a barrier. This demand restriction was recently removed in a May 2011 PSC order.

There is a documented process in place for each of the energy efficiency programs except for the new refrigerator/freezer program. These documents are listed in the table below.

Program	Reference Document	Details
Residential Gas HVAC	Res Gas Program Manual – 95 pgs	Prepared by Applied Energy Group June 1, 2009. Revised March 1, 2010. Update to program manual was planned to be completed by May 1, 2011.
Multifamily	Multi-Family Program Manual – 157 pgs	Prepared by Applied Energy Group February 1, 2010. Updated January 3, 2011.
Refrigerator/Freezer Recycling	Not Yet Prepared. This is a new program	
C&I Prescriptive – gas & electric C&I Custom – gas & electric	C&I Program Manual – 125 pgs	Prepared by Applied Energy Group June 2010.
Small Business Direct Install	Small Business Direct Install Program Manual – 204 pgs	Prepared by Applied Energy Group May 2010.
Block Bid	Block Bid Program Manual – 27 pgs	Prepared by Applied Energy Group March 2010. Update to program manual was planned to be completed by June 1, 2011.

Liberty reviewed all of the above manuals. The overall content was sound. Every major process and procedure was documented. The manuals included items such as program process, contact information, forms, call center telephone scripts, process charts, complaint resolution processes, QA processes and decision documentation for program manual changes. The Block Bid Manual content, as evidenced by the number of pages, was a little light. However, this is a custom managed program and process that does not require documentation for a wide group of users.

The programs have a designated Program Manager in place that acts as the Project Manager. They may be responsible for several programs and are assisted by Implementation Coordinator contractors for some of the programs. The Residential Gas HVAC Program contractor has an assigned Program Manager. The Multifamily Program has a contracted Implementation Coordinator. The Small Business Direct Install Program has 28 contracted field employees with management in place. The C&I programs have three Implementation Coordinators in place.

The Program Managers are relatively new to their positions. The energy efficiency programs were handled as projects before the Energy Efficiency workgroup was set up in 2011. All four workgroup managers were added in 2011. The managers have various background experiences in marketing and sales, customer billing and services or call centers. Since the Program Managers were put in place, the workgroup is now in the process of transitioning planning and general administration activities from outside consultants to the workgroup. The transitioned work will include program planning, budget planning, new program planning, technical evaluation, benefit-cost testing and other general administrative work.

The Companies' strategic plan for 2012 – 2015 will include continuing successful energy efficiency programs and replacing less productive programs with other programs which may offer a greater opportunity for customer participation and energy savings. Part of this strategy development will include partnering with the Company's evaluation contractors, DPS Staff (through the newly-formed Implementation Advisory Group), and holding focus groups meetings/strategy sessions with vendors and customers.

c. Oversight of Field Operations

There should be adequate oversight and audit of energy efficiency field operations, including contractor management, customer installations, payments and rebates.

The contractors for each of the programs are shown in the table below. In addition, there are two other contractors that will be involved in the evaluation of the programs.

Program	Implementation Contractor
Residential Gas HVAC Program	Energy Federation Inc. (EFI)
Multifamily Program	Rise Engineering
Refrigerator/Freezer Recycling	JACo
C&I Prescriptive – gas & electric C&I Custom – gas & electric	ICF International
Small Business Direct Install	EnerPath

Block Bid	Applied Energy Group (AEG)

The contractor monitoring process can be grouped into the following categories:

- Communications and weekly meetings
- Monthly Scorecards
- Monthly or bi-monthly invoicing and invoice signoffs
- Monthly tracking against goals and budgets
- Quality review of Implementation Contractor operations on site
- Formal evaluation activities mandated by the Public Service Commission

There are focused Q/A procedures and control activities in place for each of the programs.

Residential Gas HVAC Program
This is a rebate program. Rebate applications must be filled out completely, signed, accompanied by dated receipt(s) and proof of ownership (when necessary). Prior to or after paying any rebate, NYSEG and RG&E reserve the right to conduct a site visit to verify that the installed equipment is eligible for rebate. The site visit is not a safety review and is not intended for any other purposes. Site visits are conducted on approximately 5 percent of rebate applications through the Companies' contractor's subcontractor, CSG (Conservation Services Group). A rebate will not be paid if NYSEG/RG&E is not able to conduct any required verification. Early in the program 10 percent of the sites were visited. This was cut back to 5 percent after only .07 percent to .08 percent installations had reported concerns.

Multifamily Program
This is a lighting equipment direct install program for multifamily apartments. A Multifamily Rebate Program Customer Contract - Scope of Work document is presented to the customer detailing the cost and equipment to be installed. The customer must sign the Scope of Work in order for the work to begin on installation of equipment. A Multifamily Rebate Program Certificate of Completion document is submitted to the customer for signature once work is completed. Quality control is performed at various stages of the application review process by the contractor and the Companies' Program Manager.

Small Business Direct Install Program
This is a lighting equipment direct install program focused on the needs of business customers. EnerPath, the implementation contractor for this program, provides a free lighting assessment of the customers' facilities. A complete lighting inventory is processed and the customer is presented with an Energy Savings Opportunities Proposal and a Proposed Activity Report which details each suggested lighting upgrade. This includes the saving opportunity, pricing and cash flow information and the total cost of the project with the utility contribution (70 percent) and the customer's contribution (30 percent plus tax). Customers are presented with a "Customer Authorization Form" for signature to authorize the acceptance of the proposal and to schedule the installation. Upon completion of the installation and inspection of the upgrades, the customer and the installation contractor sign a Customer Completion form "Completion Document" which includes the scope of work noting any changes that occurred during installation. EnerPath, the program implementation contractor, randomly selects 30% of all projects for post-installation inspection. A general customer satisfaction query and a site inspection are performed. In addition

to the inspection process, each participating customer receives a Customer Satisfaction Phone Survey. If the customer is found to be dissatisfied, they are contacted by the project manager. The implementation contractor completes a Quality Verification Form upon completion of a site review.

C&I Prescriptive Rebate Program

This is a rebate program for specific electric or gas measures. Preapproval from NYSEG/RG&E is required on all prescriptive applications where the rebates are over $10,000. NYSEG/RG&E reserves the right to verify sales transactions and to access facilities to inspect the installed energy saving measures prior to issuing rebates or at a later time. The application must be submitted with an invoice itemizing the new equipment purchased. The invoice must indicate the date of purchase, the size, type, make, model, serial number, part number and/or equipment manufacturer specification sheets. Quality control is performed at various stages of the application review process by the Companies' contractor and by the Companies' Program Manager. The Companies' contractor has so far done 100 percent pre and post inspections using sub-contractors.

C&I Custom Rebate Program

This program is for site specific cost-effective electric and gas savings measures for retrofit opportunities in non-residential applications. The same contractors and control procedures used for the C&I Prescriptive Rebate Program are used in this program.

Block Bid Program

This program provides competitively bid funding to groups of customers, in "packages" put together by a bid aggregator, to incentivize energy efficiency programs for the non-residential electric customers. There have been two RFPs issued. RFP #1 had 6 responses. One was recently accepted. The Block Bidding Program uses a sealed-bid/pay-as-bid auction approach. To be considered in the bidding process a proposal must have a Total Resource Cost (TRC) test benefit cost ratio greater than 1.0. Projects are then ranked by their percent of Resource Benefits and proposals that save the most energy at the least cost are selected to receive funding. Individual projects and measures within the program may be required to pass a TRC test prior to payment by the Company. The bid process follows the RFP procurement process as outlined in the Iberdrola USA Procurement manual. NYSEG and RG&E perform random pre-installation and post-installation inspections to verify that the equipment the bidder identified and submitted in fact matches the equipment that is being removed and equipment being installed. To date NYSEG and RG&E have inspected more than 25 percent of all rebated measures. In addition to pre and post inspections NYSEG and RG&E require successful bidders to provide invoices of all equipment being installed and take photographs of all equipment that is being removed and all equipment that is being installed.

Refrigerator/Freezer Recycling Program

This program is an appliance rebate bounty program for the removal and recycling of functioning, inefficient second refrigerators and freezers. The program was approved by the Public Service Commission in January 2011, and the Companies are actively engaged in start-up activities. Much of the appropriate documentation and management processes are still in development. The Companies anticipated launching the program on approximately on May 1,

2011. QA activities will include quarterly file reviews at the Implementation Contractor's office, to inspect all documentation of a statistically significant number of refrigerators/freezers removed during the quarter. There will also be quarterly site inspections of the recycling facilities, to verify that removed units have all been sent to the recycling facilities, they are being recycled in an environmentally sound manner, and that related documentation is complete. The Implementation Contractor will conduct post-removal customer satisfaction surveys.

d. Goal Tracking and Reporting

Energy efficiency program goal tracking and reporting should be accurate, consistent and auditable.

The Companies track EEPS program participation against the approved goals through the monthly scorecard reports and internal management reports. Monthly management reports compile program to date savings as reported on the scorecard reports. For each program, acquired savings are compared to the overall approved goals. From this report, internal monthly goals are developed based on the acquired savings to date and the number of remaining months in the program.

The Companies also compile weekly Key Performance Indicator reports which measure program participation based on many indicators. For each program, the number of weekly assessments, applications, and acquired and cumulative savings are reported. Weekly targets are developed and modified based on the overall program goals in comparison to acquired savings to date and the number of weeks remaining in the program.

In a series of Commission orders related to approving the portfolio of programs associated with the Energy Efficiency Portfolio Standard (EEPS), the Commission approved technical manuals designed to provide a standardized, fair and transparent approach for measuring program energy savings. The five technical manuals approved between December 2008 and December 2009 cover a variety of measures applicable to the single family, multifamily and commercial/industrial sectors. In October 15, 2010, the current five manuals were consolidated and streamlined into one manual titled New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs Residential, MultiFamily, and Commercial/Industrial Measures.

The manual provides detailed instructions for calculating the energy savings for measures in every program. It includes calculation equations and all necessary energy and weather factors. Very little additional information, if any, is required from other sources. This technical manual is used by all program contractors in calculating and providing goal tracking data.

3. Conclusions

25. A documented process is in place for the selection and award of contracts for the energy efficiency programs.

Liberty found that a documented process was in place for the selection and award of contracts. This process was being followed. The Iberdrola Procurement Services Policy Manual has strict RFP guidelines that are administered by the Strategic Sourcing group. This manual was followed for the awards of the energy efficiency program contracts. There were both commercial and technical evaluations performed on each RFP. The technical evaluations were excellent and demonstrated a process for selecting the overall best contractor rather than always selecting the lowest bid.

26. Energy efficiency programs have a Project Manager and a documented PM process in place controlling costs, schedules and quality, but there is a gap in internal staffing. *(Recommendation #9)*

Liberty found that all of the energy efficiency programs had an assigned Program or Project Manager. There was also a Program Manual in place for each of the programs, with the exception of one new program.

A program manual was in place for all of the programs, except for the new refrigerator/freezer recycling program. The program manuals were excellent and contained complete documentation on all processes.

The Program Managers had backgrounds in marketing and sales, customer billing and services or call centers. One had an engineering background, but had spent the last 10 years in customer service operations. A second Manager in the group also has an engineering background, and has been involved with the Marketing and Sales and the development of the Energy Efficiency evaluation program in recent years. Overall, there was no energy engineering expertise in house. This skill set is contracted out. In general, AEG (Applied Energy Group) has provided this skill. AEG also provides some program management assistance. AEG is a consulting (energy efficiency and demand side management) and information technology company. On July 14, 2011, AEG was acquired by Ameresco. Ameresco, Inc. is a provider of comprehensive energy efficiency and renewable energy solutions for facilities throughout North America.

A staff person with technical expertise and experience in the energy efficiency area, preferably someone with CEM (Certified Energy Manager) credentials from the AEE (Association of Energy Engineers), would add value by:

- Review of technical contractors recommendations
- Rebate amount validations
- Equipment standards recommendations
- Program promotion at trade shows and events
- Technical resource for allies (HVAC, electric, building maintenance engineers)
- Marketing – technical expertise associated with the Company rather than a contracting firm
- Installation QA processes.

27. There is adequate oversight and audit of energy efficiency field operations, including contractor management, customer installations, payments and rebates.

Liberty found that there was adequate process controls and oversight of the energy efficiency field operations. Each program had focused Q/A procedures in place. The rebate processes were well documented. A contractor management program was also in place. These processes were well documented in the program manuals.

28. Energy efficiency program goal tracking and reporting are accurate, consistent and auditable.

Liberty found that the goal tracking and reporting was accurate, consistent and auditable. The methods for calculating energy savings are defined in the EEPS technical manual (New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs Residential, MultiFamily, and Commercial/Industrial Measures).

4. Recommendations

9. Add in-house technical expertise rather than use contractors. *(Conclusion #26)*

There is not any in-house technical expertise in energy engineering. This skill set must be contracted out. Also, much of the program management expertise is also contracted out. These job functions could be performed more economically by in-house personnel rather than contractors. A staff person with technical expertise and experience in the energy efficiency area, preferably someone with CEM (Certified Energy Manager) credentials from the AEE (Association of Energy Engineers), would have this skill set.

A staff person with add value by:

- Review of technical contractor recommendations
- Rebate amount validations
- Equipment standards recommendations
- Program promotion at trade shows and events
- Technical resource for allies (HVAC, electric, building maintenance engineers)
- Marketing – technical expertise associated with the company rather than a contracting firm
- Installation QA processes.

The cost for this position would come from displacing some of the current $3.4M of implementation contractor costs. An in-house position is easily expected to be more economical than a contracted position. The annual cost savings from an in-house position are expected to be from $134,000 per year.

F. Smart Grid Program

1. Background

a. Smart Grid Overview

Smart Grid has many definitions. It is a term that came in to general use in 2005. Basically Smart Grid refers to the digitization and modernization of the electric grid. The "smart" part refers to the use of intelligent digital devices that would allow utilities to manage the grid more efficiently. The vision of Smart Grid benefits is improved operational efficiency to generate savings, management and integration of renewable resources for sustainability, and improvement in reliability and customer satisfaction.

The basic elements of a Smart Grid system are:

- Communications – Gathering data from many devices and sensors and sending it to central databases in order to improve the situational awareness of the electric system.
- Monitoring and Control – Automated or remote operation of devices to improve reliability and efficiency.
- Customer Interfaces – Utilization of smart metering systems to provide data and services to both the customer and the utility.

Existing Grid	Intelligent Grid
Electromechanical	Digital
One-Way Communication	Two-Way Communication
Centralized Generation	Distributed Generation
Hierarchical	Network
Few Sensors	Sensors Throughout
Blind	Self-Monitoring
Manual Restoration	Self-Healing
Failures and Blackouts	Adaptive and Islanding
Manual Check/Test	Remote Check/Test
Limited Control	Pervasive Control
Few Customer Choices	Many Customer Choices

Some of the differences between the existing grid and the smart grid are shown in the adjacent table. Each area of the country and each utility are in different states of readiness. The main difference is due to the level of automation and technology already present on the system. The cost to modernize a utility system could be high. Many of the benefits, such as electric vehicle integration and control, are not yet present. Other benefits such as automated service restoration are only cost justifiable for large critical customers. The path to Smart Grid will be gradual and halting. Before each step is taken towards the vision of the Smart Grid, the benefits to the customer should be available. As a result, the best cost-effective activity of a utility in the arena of Smart Grid could be one of positioning rather than deployment.

b. Smart Grid Activities

The Smart Grid program activity of NYSEG & RG&E is shown in the table below.

Company	Program	Amount	Objectives/Cost Sharing	Status
NYSEG	320 MVAR of capacitor banks at 120 locations	$9 million	Enhance power flow	DOE declined
NYSEG	Phasor Measurement Units (PMU) at five substations	$2.1 million		DOE declined
NYSEG	Cooperstown and Horseheads Smart Grid Demonstration projects	$28.4 million		DOE declined
NYSEG	Low-loss bulk transformer replacement	$70 million		DOE declined
NYSEG	Efficient distribution transformer replacement	$31.5 million	Reduce losses on the distribution systems	DOE declined
NYSEG	Advanced Metering Initiative (AMI) pilot	$28.4 million	Lessen demand for electricity and natural gas	DOE declined
RG&E	AMI project	$37 million	Lessen demand for electricity and natural gas	DOE declined
RG&E	Bulk transformer replacement	$22 million		DOE declined
RG&E	Efficient transformer replacement	$10.7 million	Reduce losses on the distribution systems	DOE declined
RG&E	98 MVAR of capacitor banks at 35 locations	$2.8 million	Enhance power flow across the system	DOE declined
RG&E	PMU at one substation	$0.82 million		DOE declined
RG&E	150 MVAR Static VAR Compensator at one substation	$17.5 million		DOE declined
RG&E	304 MVAR of capacitors at 13 substations	$13.2 million		DOE declined
NYISO/NYSEG	320 MVAR of switched capacitors at six of its substations	$8.96 million	Half of the total cost is reimbursed by the DOE.	Completion is scheduled for June, 2013.
NYISO/NYSEG	Phasor Measurement Units (PMU's) at five substations and a PDC at its Energy Control Center	$2.1 million		
NYSEG	PMU at its Watercure Road Substation		Awarded funds from NYSERDA	
NYISO/RG&E	99 MVAR of switched capacitors at two substations	$2.77 million	Half of the total cost is reimbursed by the DOE.	Completion is scheduled for June, 2013.
NYISO/RG	One PMU and PDC	$820,000.		

&E				
NYSEG	Compressed air energy storage facility (CAES) Phase 1 involves a detailed engineering design and development of project financials, characterization of the salt cavern to be used for air storage.	$26.9 million	Phase 1 is budgeted up to $5 million, with the NYSEG/DOE cost sharing set at 50/50%, and NYSERDA funding of $250,000.	In-service date of late 2014 or early 2015.

Several proposals submitted for Department of Energy (DOE) funding under the American Recovery and Investment Act (ARRA) of 2009 were declined. Some of these proposals were for Smart Grid/AMI (Advanced Meter Infrastructure) demonstration projects. If the projects had been approved a portion of the funding would have been covered under the ARRA with the reminder of the funding subject to NYSPSC approval. The Smart Grid proposals were submitted to the DOE on August 26, 2009. In November 2009, the DOE rejected the Companies' Smart Grid/AMI proposals.

Central Maine Power Company (CMP) proposed developing an Advanced Meter Infrastructure (AMI) project to the Maine Public Utilities Commission in 2007. The Maine Commission conditionally approved the project in 2009. Subsequently, CMP was selected to receive a $95.9 million federal grant. CMP has received all final approvals and began full-scale installation in September 2010 for more than 600,000 customers. CMP will replace existing meters with new smart meters within two years. The new meters will provide customers with continuous, real-time information on electrical usage and enable suppliers to offer consumers new options for variable pricing or time-of-use rates. Studies have shown that consumers will use electricity more efficiently when they have real-time information about usage and price. The new meters will be will also help the company reduce costs, enhance system planning, and pinpoint problems more quickly during outages. The knowledge gained from this program should be invaluable to the NY companies in the future.

NYSEG and RG&E currently have smaller scale automated meter systems which they are interested in updating and expanding in the next 5 years. Specifically:

- RG&E has a small AMR (Automated Meter Reading) system serving 28,000 electric and gas customers. The system utilizes a "drive by" Itron system to record meter reads. The system has been functioning well for 15 years. However the 13,000 gas AMR devices recording the reads have reached their end of life and need to be replaced. RG&E will be looking at updating these indexes over the next few years. Expansion of the RG&E program using updated AMR technology is also under consideration.
- NYSEG and RG&E have about 2,000 large gas meters on a Metretek system, connected through telephone lines for daily reads for Gas Transportation customers.
- NYSEG and RG&E also have our larger customers on mandatory hour pricing program. The system utilizes customer phone lines to provide meter interval data to the central billing system.

There are several active projects listed in the table above that are underway at NYSEG and RG&E.

Phasor Measurement Units/Switched Capacitors

NYSEG and RG&E have joined the other New York Transmission Owners (TOs) in the Smart Grid Investment Grant (SGIG) under the leadership of the New York Independent System Operator (ISO). The SGIG is a stimulus grant from the U.S. Department of Energy (DOE) whereby the DOE reimburses each of the TOs for 50 percent of its costs in designing, constructing, and installing Phasor Measurement Units (PMUs) and Switched Capacitor banks on each TO's transmission system. NYSEG and RG&E each have a PMU project and Switched Capacitor project for each company's system, for a total of four projects. Through the ISO, all of the TOs will integrate their PMU and Switched Capacitor installations into the New York electric grid.

NYSEG and RG&E are currently in the engineering stages of their Switched Capacitor and PMU projects. Acquisition and installation of the Switched Capacitor projects are anticipated for later 2011 and into 2012. Contractors haven't been selected for the Companies' PMU projects. This is expected soon, with acquisition and installation to begin later this year and into 2012. The expected completion date for all four NYSEG/RG&E SGIG projects is June, 2013.

The PMUs and capacitor banks being installed at NYSEG and RG&E are pieces of a larger plan. Eventually, the NYISO's PMU network will connect with PMU networks in New England, the mid-Atlantic, the Midwest and Ontario, Canada to create a broader situational awareness throughout the Eastern Interconnection Planning Collaborative, a coalition of 24 transmission planning authorities in the eastern United States and Canada. The NYISO estimates the PMUs and capacitor banks will save the state $9M per year in reduced losses and higher reliability.

Advanced Compressed Air Energy Storage (CAES) Demonstration 150MW Plant

This project involves Energy East Corporation (as the applicant and former owner of NYSEG) to perform the phased planning, design, engineering, construction, operation, performance monitoring, and cost/benefit assessment of an advanced Compressed Air Energy Storage (CAES) plant using an existing underground salt cavern. The proposed site is located in NYSEG's service territory in the Town of Reading, New York, at the southern end of Seneca Lake, in New York State's Finger Lakes region. The overall objective of the advanced CAES demonstration project is to improve reliability of the grid by creating storage and more desirable dispatch for wind energy.

Other organizations providing financial support in this collaborative project are the Electric Power Research Institute (EPRI) and the New York State Energy Research and Development Authority (NYSERDA). The New York State Governor's office, the NY Smart Grid Consortium, Customized Energy Solutions, Energy Storage and Power, and Dresser-Rand are all in support of the proposed project.

NYSEG submitted a project proposal to the DOE to develop a compressed air energy storage facility (CAES) adjacent to the Seneca gas storage facility on August 26, 2009. NYSEG was awarded a $26.9 million smart grid demonstration grant which the Company formally accepted on November 20, 2010.

The R&D project development is proposed to be completed in two phases.

Phase I involves a detailed engineering design and development of project financials, characterization of the salt cavern to be used for air storage, and a draft NYSIO interconnection filing. This phase is budgeted up to $5 million, with the NYSEG/DOE cost sharing set at 50/50%, and NYSERDA funding of $250,000.

Phase II would include the actual plant construction with a planned targeted in-service date of late 2014 or early 2015. There will be a NYSEG/DOE cost sharing set at 24/76% up to the limit of the remainder of the remaining $26.9 million grant unspent during Phase I, and $750,000 of NYSERDA funding.

CAES plants use off-peak electricity to compress air into an underground reservoir or an above ground air storage system. When electricity is needed, the compressed air is withdrawn from air storage, heated via combustion with natural gas or preheated from the exhaust of a natural gas turbine, and passed through an expansion turbine to drive an electric generator. CAES plants burn about one-third the amount of fuel compared to conventional combustion turbines and produce about one-third the pollutants per kilowatt hour (kWh) generated compared to a conventional combustion turbine.

The advanced CAES facility thus will generally charge during off-peak periods when excess, low-cost electricity is available and discharge during on-peak hours. Unique to this project, the CAES facility will be capable of quickly switching from charging to discharging to further take advantage of system needs during on-peak periods when the wind generation is beyond the system needs or there is a sudden loss of wind generation. In doing so, more renewable energy can be captured and/or controlled while reducing the extreme volatility in market pricing and operation. In this way, there is a better asset utilization of wind/renewable energy and reduction in the need to purchase ramping and regulation from conventional fossil fuel based power plants.

As this is an R&D grid-scale demonstration project, the economic benefits are not well known in advance. There is an Economic Data Collection Plan to gather this information. Iberdrola will perform cost-benefit analyses using the data collected during plant operation to provide a cost/benefit analysis. The metrics listed below will form the basis for project success. Various measurements will be taken as the project progresses to enable quantification of these metrics. Metrics will be calculated monthly and rolled up for quarterly and annual reporting, for a period of four years of operation. Proposed metrics include the following:

- Capacity factor
- Cost savings
- Variable and fixed operating costs
- Technical performance measures
- Environmental performance
- Renewable energy utilization.

c. NYSEG/RG&E Strategic Plan for Smart Grid

On July 16, 2010, the Commission instituted Case 10-E-0285 - Proceeding on Motion of the Commission to Consider Regulatory Policies Regarding Smart Grid Systems and the Modernization of the Electric Grid. The Order sought parties' comments on appropriate regulatory policies that would encourage electric utilities to develop smart grid systems. The Companies' filed their comments on September 17, 2010. As detailed in these comments, the Companies' proposed a four stage phased approach to achieving the goal of Smart grid implementation, with the timing of each phase being flexible to accommodate New York specific needs and requirements. Under this phased approach short-term investments would be focused on installation and utilization of network components that are and will be useful for a future Smart Grid. Longer-term investments would proceed at the "speed of value."

Stage 1: Purchase IP-Enabled (Internet Protocol) Control and Monitoring Devices for the Distribution System

Stage 1 reflects investment that should be occurring today. Stage 1 seeks to have all new grid control and monitoring devices that are Smart-Grid capable. Equipment installed today that does not have IP communications ability will not be able to function or participate in any future Smart Grid. Purchasing equipment capable of IP communication avoids a situation occurring where a "dumb" device installed today must be replaced before the end of its service life. The cost of this phase would be incremental dollars spent on the purchases of new reclosers, regulators and other line devices.

Stage 2: Build IP-Based Communications Systems to Cover the Service Territory

Stage 2 represents a time horizon for investment in the next three years. Line devices purchased in Stage 1 will need to communicate with central grid managers to become fully operational. This requires utility investment in a communications network. The communications network must provide 100% coverage of the service area. It must also provide high speed data communications from the substations to the central data centers.

Stage 3: Delivering Specific Smart Grid Projects on the Distribution Network

Stage 3 represents three years onward. By itself, delivering a communications network as part of Stage 2 creates the foundation for the Smart Grid. By connecting Stage 1 incremental investments through this communications network, 2-way control and monitoring will become operational for certain components giving immediate incremental benefits to customers. Stage 3 takes these benefits further by focusing utility investments directly on new, specific Smart Grid projects with strong business cases. The Companies believe that more future business cases will emerge as the results from ARRA projects are delivered. However, at present, the Companies believe three strong business cases are emerging. These cases are volt/var control to flatten the voltage profile, reducing peak load demand, and improving reliability. By having access to significantly more data, delivery companies can, at appropriate points in the network, install automated restoration devices and smart isolation switches that will automatically correct disturbances and minimize the duration of outages.

Stage 4: Introducing AMI for all Customers

Stage 4 represents Smart Grid investment five years onward. The Companies and Iberdrola firmly believe in the cost-effectiveness of AMI, as evidenced by the Companies' past filings regarding AMI and Iberdrola's investment in Maine for an AMI system to serve 600,000 customers. However, the Companies also understand the concerns about obtaining hard evidence of the value of the AMI benefit of demand response. The Companies see significant benefits from this investment in two areas: customer service and outage management.

2. Findings

a. Responsibility for Assessing Developments

RG&E and NYSEG should clearly assign responsibility for assessing industry and governmental (particularly DOE and NIST) developments in Smart Grid development and for assessing current network capabilities and potential improvement plans in light of those developments.

There is no formal organizational structure in place for the Smart Grid program. There are several areas within NYSEG and RG&E that participate in industry forums and monitor activity associated with Smart Grid development.

System Planning participates in national, regional, and state-wide studies and working groups associated with system capabilities and reviews the various Smart Grid pilot projects and their effectiveness on reducing system peak loading.

Energy Supply & Transmission Services participate in regional and state-wide industry groups that monitor the Smart Grid technology advances and review their capability to impact future reliability and economic needs for system capability.

In addition to the departments within RG&E and NYSEG, Iberdrola USA provides monitoring, support and knowledge sharing on Smart Grid activities within the Iberdrola USA family of companies.

b. Work Actively to Address Issues

The utilities should work actively with other state electricity distribution utilities and the Commission to address issues of deployment, standards, equipment, services, and cost recovery as they affect all New York providers commonly and their operations specifically.

One organization in the state that is involved in this area is the New York State Smart Grid Consortium. The NYS Smart Grid Consortium is a not-for-profit 501(c) 6 corporation, incorporated on July 22, 2009, to harness the unique resources of the state as it manages the collaborative development of the Smart Grid. The Consortium was founded in 2008 when leaders determined that meaningful progress required the inclusion of all stakeholders to define and work toward a common Smart Grid vision. The primary objective in forming the Consortium was to harness the collective efforts of key stakeholders across the state to implement an electric power system that is efficient, secure and reliable while simultaneously facilitating renewable resources and enabling customers to reduce cost and energy consumption.

The Consortium represents a key public-private partnership to promote broad statewide implementation of the Smart Grid. It is the only organization of its scale in the U.S. that is committed to representing all major contributors across the energy value chain from utilities, markets, operators, industry, academia, government and end-users.

The Companies attended the NY State Smart Grid Consortium meeting that was held in NYC on August 5, 2010. The Companies held discussions with the consortium regarding potential membership and have not made a final determination on joining the consortium at this time.

Their decision to join this organization or any organization is based on the cost and value that their customers will receive. Based on information received from the Smart Grid Consortium, the current cost of membership is $75,000 per company per year. The Companies have not completed any quantitative cost/benefit analysis regarding potential membership.

Other New York electrical utilities that are members of the Consortium are Central Hudson G&E, Consolidated Edison, Long Island Power Authority, National Grid, New York Power Authority and New York Independent System Operator. The Consortium website listed both NYSEG and RG&E as members at the time of this audit. The Companies contacted the consortium on 9/26/11 and requested that the website be corrected to remove the names of NYSEG and RG&E from the membership listing on their website.

c. Structured Process for Examining Costs & Benefits

RG&E and NYSEG should have an analytically sound and structured process for examining the costs and benefits in a comprehensive and quantitative manner of network improvements, in order to be prepared to respond promptly and effectively to increased capabilities, emerging standards, regulatory programs and requirements, and customer expectations.

There are several active projects and initiatives that would increase the Smart Grid readiness. These initiatives were not undertaken solely for Smart Grid benefits. However, they have the potential capability to be utilized in a future Smart Grid network, in addition to providing immediate benefits.

Line Devices
In 2010, a project was undertaken at both NYSEG and RG&E to review the distribution systems and evaluate circuits for new electronic recloser installations. The goal was to improve the SAIFI reliability index by reducing the number of customers interrupted on each of the targeted circuits. As part of the equipment selection process, specific attention was given to ensure that all new electronic reclosers being ordered for the project were communication ready to anticipate the potential for future Smart Grid applications through remote informational access and control. This project included 85 new electronic recloser installations at NYSEG and 48 at RG&E.

In 2011, a review of the equipment purchasing descriptions for all NYSEG and RG&E reclosers, voltage regulators, switched capacitor banks, and network protectors was undertaken to ensure that all future purchases of these equipment types included the option for communication equipment. The goal of this review was to ensure that the equipment that was being purchased today was compatible with future Smart Grid applications and would not require significant upgrades. This action is mentioned in the strategic Smart Grid plan in section A.3 above.

Energy Control Center
A new Energy Control Center Project will enhance the Distribution Management capabilities of the electrical system. They are installing a Siemens Spectrum Power Control System. This Spectrum system will be fully integrated with a new Graphical Information System ("GIS") and the corporate SAP, which provides accounting, work management, and customer information databases.

The most valuable capability being added is the Spectrum Systems' ability to integrate the information from many sources as well as real time data from all levels of the transmission and distribution networks. The Spectrum system then prioritizes and displays this information to maximize the operator's situational awareness.

Limitations of the current system used by distribution operators for trouble and outage management are overcome with new Spectrum system:

- Spectrum combines information from both customer calls and tele-metered information from the control system to provide distribution operators with true system status.
- Spectrum allows distribution operators to send tele-control commands to distribution system components to facilitate outage restoration.
- GIS data is incorporated with the distribution system status in the Spectrum system allowing operators to step from tabular data, to schematic views of the system, to geographic mappings (including satellite photo details). This capability allows operators to properly identify outage locations and direct crews to the correct location.
- Electronic feedback from crews and the work management system is displayed graphically and in tabular format which allow the distribution operators to maximize the restoration crew efficiency in real time.
- As an integrated system this flexibility allows transmission system operators to assist with transmission system outage restoration and also with distribution system management.
- The system can be operated in decentralized mode providing local information and field crew control capabilities directly to restoration teams and storm centers.
- The GIS also adds the ability to generate outage restoration maps including current system configurations. The system integrates these maps with GIS linked circuit assessments collected through the restoration evaluation process.

Overcoming these limitations decreases outage durations and the costs of restoration, both representing substantial benefits to customers.

Remote Terminal Units (RTUs)

There are currently three groups of RTU replacement projects underway in Iberdrola USA (New York). There is a project at NYSEG that is in the construction phase to replace 30 RTU's at various locations throughout the system. All but five of these replacements are completed, which will be done by the end of 2011. The second project is targeting the replacement of 12 RTU's at NYSEG in the Brewster Division. This project is specifically intended to address reliability concerns in the division by replacing obsolete equipment and adding additional control devices (motor operated switches) in order to improve the remote operability of these devices. Ultimately, the objective is to provide for reliability improvements in the Brewster Division by giving more information and control to the operators in the Energy Control Center (ECC). This project is currently in the detailed design phase. The third project includes a group of seven distribution substations that will have obsolete RTU's replaced at locations at RGE. This project is currently in the detailed engineering phase.

IEC-61850 Substation Communication Standard

IEC-61850 is a part of the International Electrotechnical Commission's (IEC) Technical Committee 57 (TC57) architecture for electric power systems. It is widely used in Europe and is being introduced here. IEC-61850 is a new substation protection and control protocol that takes advantage of modern high speed LAN communications. It has the advantage of one common communication language used by the substation devices. Iberdrola started a project last year to investigate the implementation of this new standard. A 12 to 14 person technical group was formed that includes personnel from the ECC, SCADA operators, substation, distribution, security, etc. The groups output will be a final document on the system specifications. A draft has already been prepared. By the end of 2011 a final document will be available. Implementation will first occur as a pilot program in Maine on a large transmission project that involves a number of new or rebuilt substations.

The benefits are well known and accepted.

- The main benefit is savings on the cost of wiring up a substation. The IEC system uses all fiber, which is economical compared to hard wiring each substation device.
- The fast messaging to support real-time communications is another benefit.
- The ability to use a mixture of different equipment vendors in the same substation is a benefit.
- After the initial setup of IEC protocols is done (tables, diagrams, etc.) the cost of substation engineering is reduced.
- There is better quality information available from the facility.
- SCADA can be used to program the relays settings, which is a savings in labor.
- Fault events are better recorded.

These projects will all provide more information and control capability at the ECC level for substation and distribution control devices.

d. Proactive Role Pursing Opportunities

RG&E and NYSEG should take a proactive role in examining the availability of funding support for network enhancements, and should aggressively pursue opportunities that will have demonstrable benefits for customers at effective cost.

The activities listed in Section A.2 pursued DOE funding of Smart Grid projects in several areas. These areas were:

- Switched capacitor banks
- Phasor measurement units
- Low loss transformers
- Advanced Metering Initiatives
- Bulk transformer replacements
- Off-peak energy storage (CAES system).

3. Conclusions

29. RG&E and NYSEG have assigned responsibility for assessing industry and governmental (particularly DOE and NIST) developments in Smart Grid development

and for assessing current network capabilities and potential improvement plans in light of those developments.

The responsibility for Smart Grid governance at NYSEG and RG&E resides in the functional area. System Planning, Energy Supply and Transmission are involved in assessing and monitoring developments in their respective area.

In addition to the departments within RG&E and NYSEG, Iberdrola USA provides monitoring, support and knowledge sharing on Smart Grid activities within the Iberdrola USA family of companies. The overall responsibility of Smart Grid assessment and strategic planning has been assigned at the Iberdrola USA level rather than be duplicated in the member companies. Overall, this approach seems to be working for NYSEG and RG&E. A strategic approach for Smart Grid has been developed. Stage 1 of this plan, the purchase of IP-Enabled (Internet Protocol) devices for the distribution system, has been implemented.

30. The utilities have not worked actively with other state electricity distribution utilities and the Commission to address issues of deployment, standards, equipment, services, and cost recovery.

Iberdrola is not an active player in the development of Smart Grid standards. They are a marginal partner with the other electrical utilities in the state on the NY State Smart Grid Consortium. There was also some confusion noted on the Consortium membership status of NYSEG and RG&E.

Iberdrola is participating on some DOE sponsored projects, which were put into motion by the previous Energy East organization.

31. RG&E and NYSEG have an analytically sound and structured process for examining the costs and benefits of network improvements.

Overall, Liberty found the network improvements being done are actively positioning Iberdrola for future Smart Grid operations. The communication capability in line devices is a cost effective addition. The upgrades of substation RTUs and the Energy Control Center systems will allow for immediate benefits while also being a step towards a Smart Grid. The IEC-61850 substation communication standard is an innovative program. These projects will all provide more information and control capability.

On July 16, 2010, the Commission instituted Case 10-E-0285 - Proceeding on Motion of the Commission to Consider Regulatory Policies Regarding Smart Grid Systems and the Modernization of the Electric Grid. The Order sought parties' comments on appropriate regulatory policies that would encourage electric utilities to develop Smart Grid systems. The Companies' filed their comments on September 17, 2010. In this response they gave a strategic view of a structured process for Smart Grid implementation and cost/benefit examinations.

32. RG&E and NYSEG have taken a proactive role in examining the availability of funding support for network enhancements, and should aggressively pursue opportunities that will have demonstrable benefits for customers at effective cost.

Overall, Liberty found they were taking a proactive role in examining funding support for Smart Grid initiatives. There were a number of projects submitted for DOE funding. While many of these projects were rejected by the DOE, this indicates an aggressive pursuit of funding opportunities. Iberdrola was successful in obtaining funding support for several projects from NYSERDA and DOE.

4. Recommendations

None.

Program and Project Planning and Management – Gas

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XII. Program and Project Planning and Management - Gas

A. Background

This chapter examines RG&E and NYSEG's gas business project management programs and activities. Both companies have maintained good gas safety and compliance records over the last five years. Staffing levels however have declined in both gas engineering and gas operations in recent years, making it more difficult to continue to meet gas safety and compliance commitments as well as maintain and update gas infrastructure.

The capital budget was expanded to more than $2 billion per year, producing a doubling since the 2010 rate case. It is appropriate then to question whether the Companies' current project management capabilities and tools can accommodate this sizeable increase in capital budget funding and if these capabilities are also growing with the budget. This fundamental question forms a primary basis of the examination Liberty performed.

Gas Engineering oversees the project management aspects of gas construction projects, including planning, design, engineering and close-out. When a project reaches the construction phase, the job is released to Field Operations to fulfill the construction management function. Construction management by Field Operations may include scheduling the work to meet the project management schedule, identifying internal or external resources, creating and submitting the procurement materials, and performing construction oversight and inspection activities. Upon completion of the construction phase, the work package returns to engineering for close out activities.

The Companies employ project management approaches in their gas transmission work, but there are numerous opportunities for improvement in the program, especially in scope control and cost management. The Companies make little use of project management principles and techniques in gas distribution projects. There is no structured project management program and currently there are no dedicated project managers. IUSA has a major improvement opportunity in this area of its gas business. Liberty is optimistic that the Companies can make real gains through the use of more formalized project management programs and methods.

NYSEG and RG&E provided gas delivery services to approximately 600,000 customers in New York State, in 2010, delivering more than 90 million dekatherms of natural gas. The table below describes the Companies' natural gas transmission and distribution system.

Facilities	**NYSEG**	**RG&E**	**Total**
Transmission Pipeline (miles)	**72**	**106**	**178**
Distribution Pipeline (miles)	**4,698**	**4,709**	**9,407**
Protected Steel	2,218	2,482	4,700
Unprotected Steel	339	369	708
Cast Iron	1	91	92
Plastic	2,108	1,767	3,875
Ductile Iron	32	0	32
Services (number)	**224,305**	**271,650**	**495,955**

Protected Steel	34,638	73,899	108,537
Unprotected Steel	24,166	11,165	35,331
Cast Iron	0	0	0
Plastic	157,112	178,451	335,563
Other	8,389	8,135	16,524
Regulator Stations (with gate stations)	**544**	**315**	**859**

B. Findings

1. Long-term Investment Planning

The 2011-2015 NYSEG and RG&E Capital Investment Plan describes the key gas system business strategies as to:

- Safely operate gas transmission and distributions systems.
- Achieve all NYPSC gas service quality performance measures.
- Minimize leaks through corrosion control, leak repair, and replacement of leak prone pipe.
- Provide innovative, cost-effective and timely planning, engineering, and design services that meet or exceed customer expectations.

The 2011-2015 capital investment plan describes planned gas projects and programs (they total $397 million) that the Companies believe will achieve these strategic objectives over the next five years. In addition to the above major capital projects, the Companies plan to invest in ongoing programs to replace leak prone distribution and transmission mains and services, as well as any obsolete or poor condition equipment at regulator and gate stations. The following table summarizes planned capital investment over the next four years:

RG&E and NYSEG Gas Capital Investment Plan ($000)[1]

	2011	2012	2013	2014	2015	Total
Projects	$14,417	$4,475	$0	$1,050	$0	$19,942
Programs	$65,173	$69,131	$78,500	$80,855	$83,280	$376,939
Total	$79,590	$73,606	$78,500	$81,905	$83,280	$396,881

Seven major gas projects are planned over the next five years, representing $20 million in capital spending:

- Seneca West Pipeline—Five mile extension of the Seneca West Pipeline to Elmira
- Oakwood Avenue—Installation of a new steel main to increase supply flexibility
- Canandaigua Cast Iron Replacement—Replacing cast iron gas main in downtown Canandaigua

[1] DR 0194, Attachment 5

- Lansing Interconnection—Reinforcement project to support increasing demands in Lansing
- Gas SCADA—Replacement of the Gas SCADA system
- Southwest 60 System Improvements—Increase capacity to support industrial growth and improve system reliability
- Seneca Lake Storage Facility—Replace Program Logic Control (PLC) equipment.

2. Projected Spending

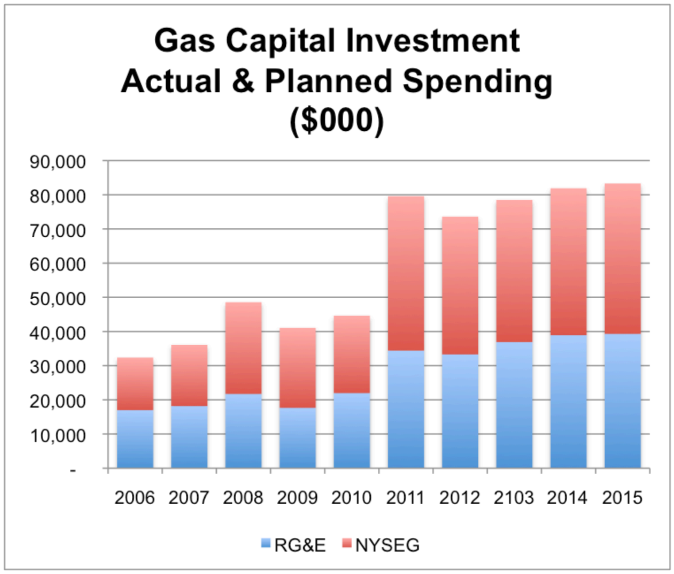
A breakdown of planned gas project spending by year is presented in the following table:

RG&E and NYSEG Capital Spending on Gas Projects ($000)						
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Seneca West Pipeline	$5,792					$5,792
Oakwood Avenue to Gardner Rd		$4,475				$4,475
Canandaigua Cast Iron Replacement	$1,035					$1,035
Lansing Interconnect				$1,050		$1,050
Gas SCADA System	$2,279					$2,279
Southwest 60 System Improvements	$3,460					$3,460
Seneca Lake Storage*	$1,851					$1,851
Total	**$14,417**	**$4,475**		**$1,050**		**$19,942**

* This capital project was removed after the sale of Seneca Storage to Inergy.

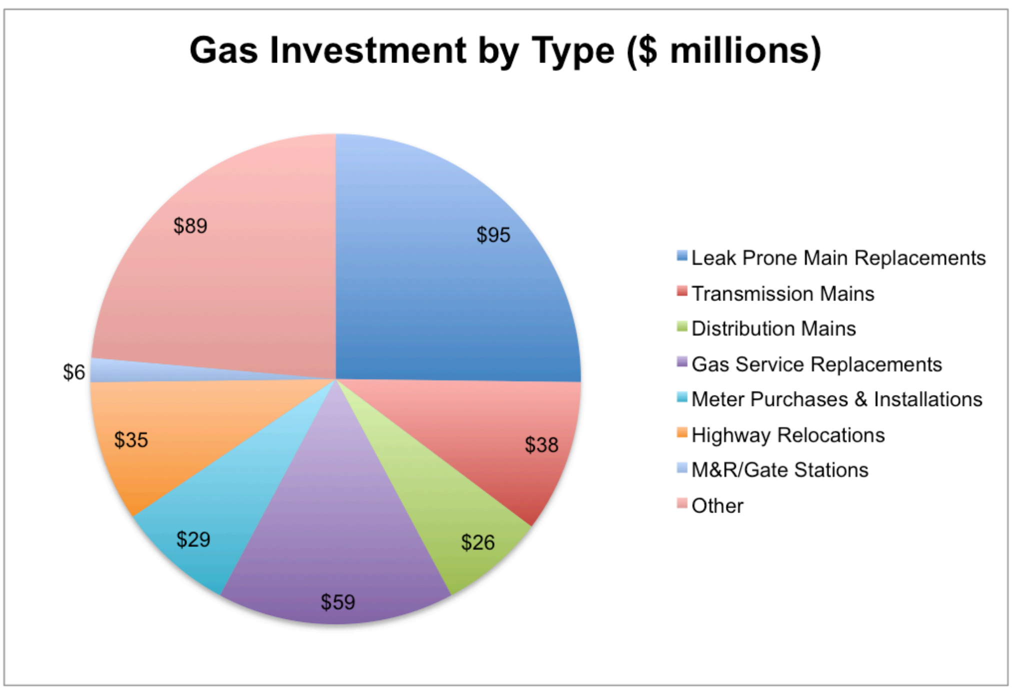
The IUSA capital budget for both electric and gas has increased considerably over the last year. The 2011 capital budget for all the businesses exceeded $2 billion. The gas business unit's share of the capital budget represents $397 million (about 18 percent of the total) and is in keeping with its size, as measured by revenue. This section of the report will focus on gas project and program management. Other chapters focus on gas supply (Chapter IX) and gas planning (Chapter VII). These three gas activities, supply, planning and project/program management (execution) are inter-related and dependent on each other for a successful capital spending plan and a reliable system to serve customers.

IUSA will be consistently increasing both the gas business unit GBU O&M (Operations and Maintenance) and capital budgets over the next several years. The table and graph show the five-year trend of increased planned spending in the capital budget and prior spending.



The 2010 rate case (reference Appendix L) approved an increase in the gas capital budget through 2013, in order to replace significant amounts of leak prone (bare steel without cathodic protection) mains and small diameter cast iron mains prone to breaks and cracks. The large percentage increase in gas capital spending in 2011 over 2010 will therefore continue at the current rate for at least several more years and possibly longer.

The following chart shows a breakdown of total capital program spending, from 2011 through 2015, by type of investment.

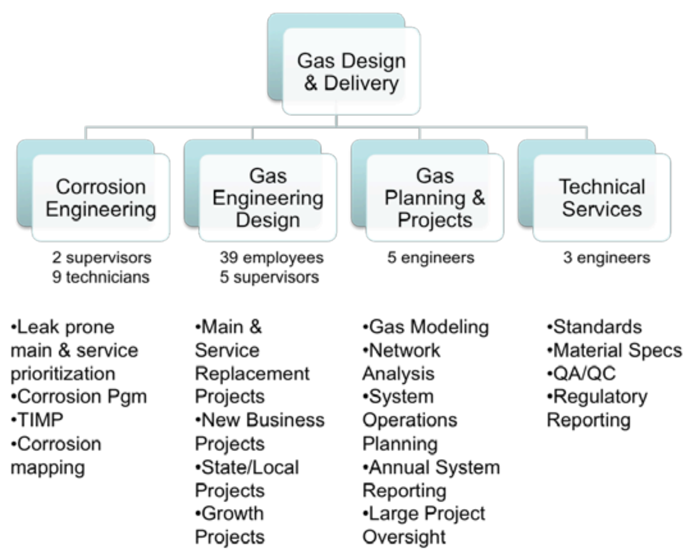


RG&E and NYSEG Capital Spending on Gas Programs ($000)

	2011	2012	2013	2014	2015	TOTAL
Leak Prone Main Replacement Program	$18,140	$18,073	$18,819	$19,597	$20,409	$95,038
Transmission Mains	$1,879	$1,716	$11,035	$11,366	$11,707	$37,703
Distribution Mains	$3,813	$7,567	$4,659	$4,799	$4,493	$253,311
Gas Service Replacements	$10,729	$11,769	$11,918	$12,062	$12,199	$58,677
Meter Purchases/Installation	$8,005	$8,245	$4,236	$4,363	$4,494	$29,343
M&R / Gate Stations	$1,925	$19,83	$766	$789	$813	$6,276
Highway Relocations	$8,882	$9,149	$5,509	$5,675	$5,844	$35,059
Other	$11,800	$10,629	$21,558	$22,204	$22,871	$89,062
Total	**$65,173**	**$69,131**	**$78,500**	**$80,855**	**$82,830**	**$376,489**

3. Engineering Organization

The following chart shows the Gas Engineering organization for RG&E and NYSEG.

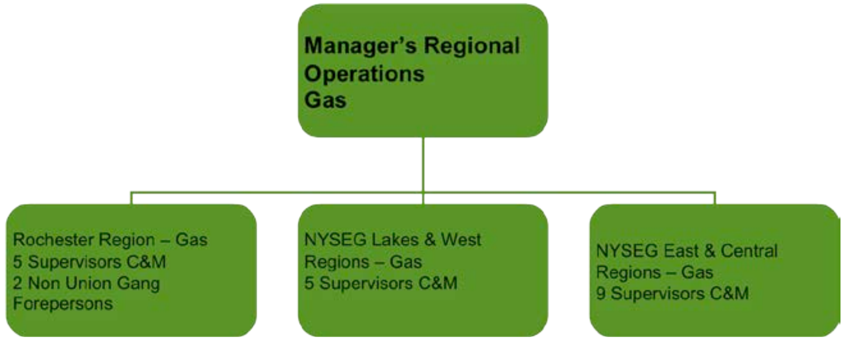


4. Operations Organization

In 2010, Gas Operations was re-organized to establish a Gas Operations Business Unit, headed up by a vice president of Gas Operations. Three regional gas operations managers, representing three geographic areas, report to this executive:

- Rochester (5 supervisors, 138 employees, 5 offices)
- NYSEG West/Lakes (5 supervisors, 72 employees, 7 offices)
- NYSEG Central/East (9 supervisors, 114 employees, 18 offices).

The following chart shows the Iberdrola Gas Operations organization.

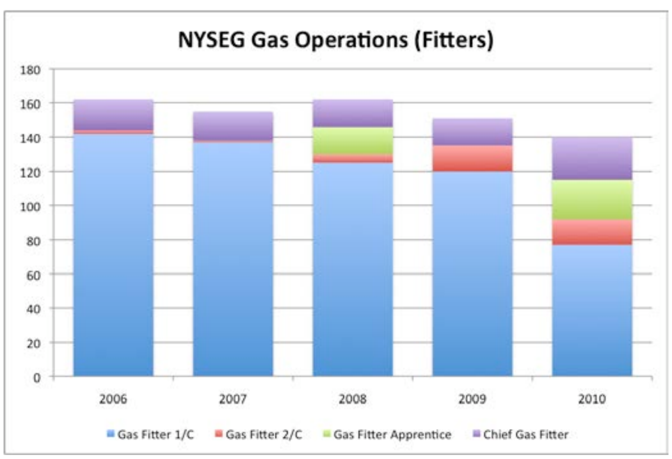


RG&E's service territory is fairly compact and centered around the city of Rochester; however, NYSEG's service territory is spread across New York State, and covers many rural areas. Therefore 19 (of 25) NYSEG gas operations offices have five or less gas operations employees.

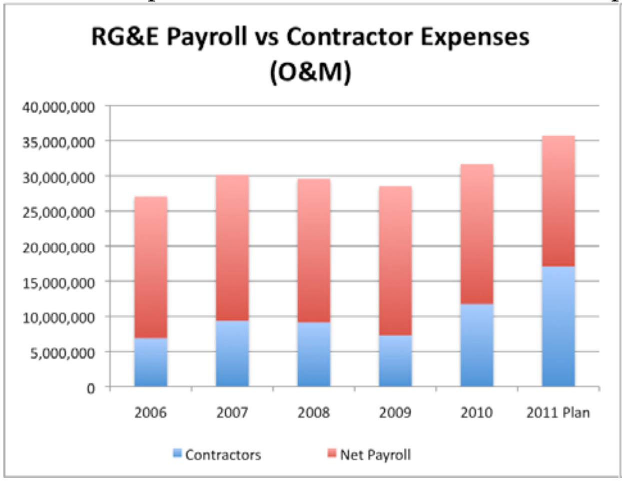
The reorganization was viewed by most individuals in gas operations as a significant improvement, primarily because it split gas operations from electric operations. With the change, gas managers and supervisors assumed responsibility for operating the gas system in the most efficient and safe manner possible. This new gas operations organization provides a greater focus on the business, including budget, performance metrics, and costs. However, there is a learning curve to develop these management skills within the existing organization.

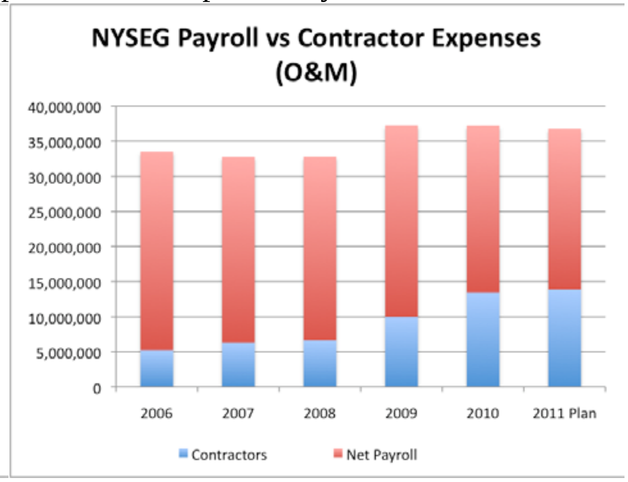
5. Staffing Reductions

Recent voluntary retirement programs have taken a toll on the gas operations organization. A significant number of gas operations employees left the Company. Moreover, the Company has not replaced any staff for a number of years. RG&E has not hired any hourly workers in gas operations since 2000. In addition, remaining employees comprise an aging work force, which causes concern in the long term. At RG&E, the dwindling and aging work force becomes more challenging with its high degree of job specialization. The following chart demonstrates the decline in gas operations fitters and the change in work group composition at NYSEG over the last four to five years.



The gas operations group must therefore often borrow employees from other work groups, or rely on contractors to complete mandated work. The following charts show that contractor usage within Gas Operations has increased at both Companies over the past five years.





6. Performance Metrics

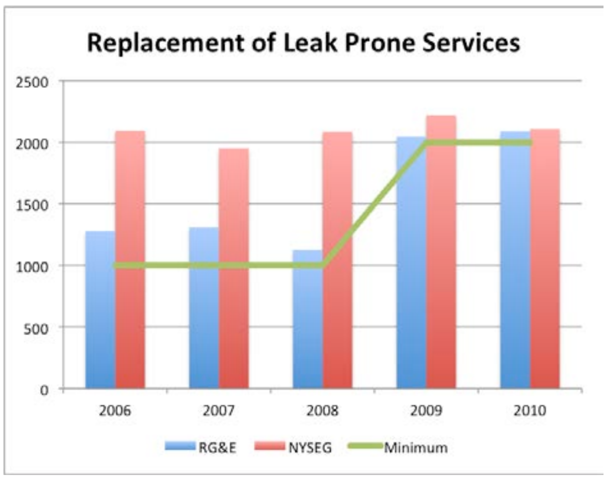
In spite of low staffing levels, most of the mandated work is performed each year. The NYS PSC collects a series of safety and performance metrics for all of the gas utilities across the state on a yearly basis. NYSEG and RG&E gas safety and reliability performance for year-end 2010 is displayed in the following table.

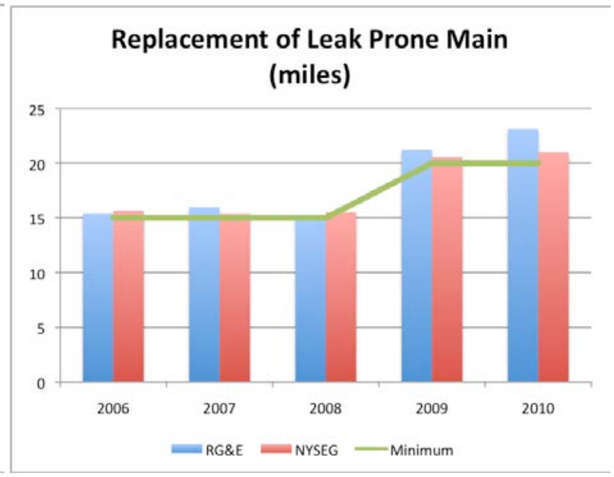
2010 Year-End Performance		NYSEG	RG&E
Emergency Response			
Natural Gas Leak Response <=30 min	Actual	80.22%	90.77%
	Target	75.00%	75.00%
Natural Gas Leak Response <=45 min	Actual	95.26%	98.29%
	Target	90.00%	90.00%
Natural Gas Leak Response <=60 min	Actual	99.02%	99.76%
	Target	95.00%	95.00%
Leak Management			
Pending Leaks (all types)	Actual	42	158
	Target	100	200
Damage Prevention			
Overall Damages per 1,000 Tickets	Actual	1.74	1.55
	Target	2	2
Mismarks per 1,000 Tickets	Actual	0.36	0.36
	Target	0.5	0.5
Company Damages per 1,000 Tickets	Actual	0.05	0.11
	Target	0.2	0.2
Gas Regulatory & Safety Targets			
Bare Steel & Leak Prone Main-miles	Actual	21.01	23.12

	Target	20	20
Bare Steel & Leak Prone Services #	Actual	2,104	2,087
	Target	2,000	2,000

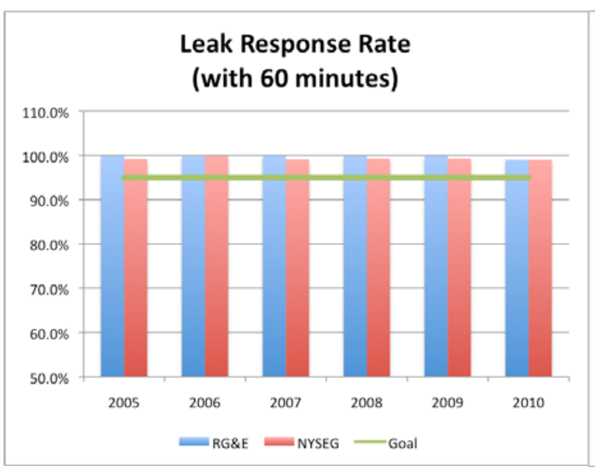
IUSA has an exemplary compliance and safety record to-date. Both Companies have met or exceeded all gas safety performance goals during 2005 – 2010. In addition, the IUSA gas companies also repair all classes of leaks, rather than only the mandated classes. This additional work ensures that the respective gas systems are operated as safely as possible and that greenhouse gases are minimized along with the safety threat of gas leaks to the general public and customers.

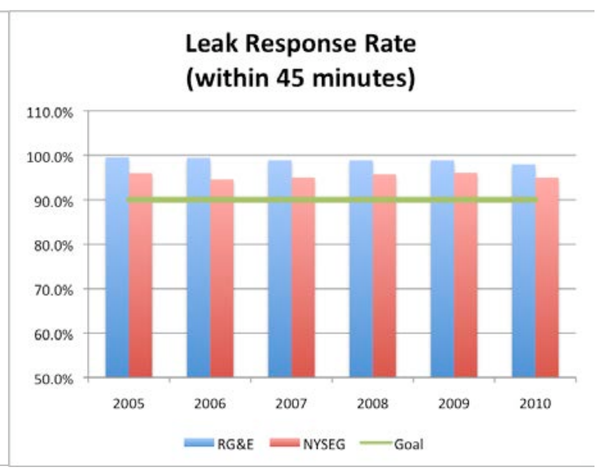
NYSEG and RG&E were the only companies in NY that have implemented a bare steel main isolation program (10 miles per year) to extend the life of leak-prone pipe.

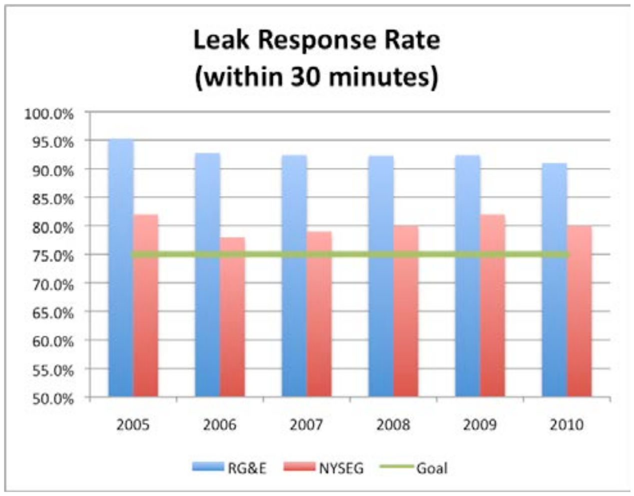


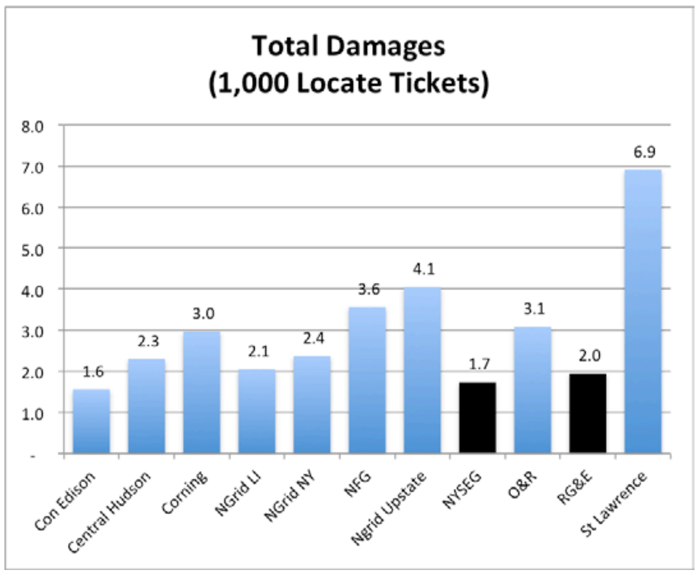


Over the past five years, each Company has also met or exceeded the PSC target for emergency response. In addition, RG&E has consistently led all NY utilities in response to calls in <30 minutes.









NYSEG and RG&E have also made significant progress in reducing third-party damages.

- The Companies seeks to be the best in NYS; therefore all safety and mandated work is tracked and managed closely.
- Recently the Companies have brought leak survey activities back in-house, and have moved from a three – five year program to a three year program.
- The bulk of the leaks being found result from the surveys with very few being called by customers.
- This year the Companies will attempt to cover two-thirds of the territory; the required one-third will be completed by company employees and the other one-third by a contractor.
- This is an aggressive schedule for existing staffing, and will identify even more leaks that need to be repaired by year-end.
- The PSC goal of <100 leaks (NYSEG) and <200 leaks (RG&E) open on December 31, 2011 (NYSEG and RG&E count all leak classes as workable and repair all leaks).

7. Project Management

Firms requiring large investments in plant; *e.g.*, utilities, by necessity have developed their own approaches to project management. Some projects can at times lend themselves to "turn-key" efforts by contractors; however, they comprise the exception, not the rule. Project management is too important for the typical utility to delegate; therefore, large utilities all have dedicated programs of project management, although they vary in approach, sophistication, and quality.

Project management programs come in many variations, but all should include a number of standard components to meet key requirements. These components include scope, schedule, quality, cost, risk, resources, safety, procurement, and communications. An effective program will contain all of these elements and perhaps more, but three always emerge as the bottom line objectives: cost, schedule and quality. The balancing of these three parameters presents the principal challenge to the skill of project managers.

The criteria by which Liberty evaluated project and program management - gas included the following:

Process structure and phases

- A project management program should be in place that addresses all of the elements of project management and is targeted at appropriate cross-functional projects.
- A team of project/program managers should exist that have experience in all elements of project management and have suitable credibility within the necessary work processes.
- Large projects/programs should be provided with dedicated support resources, including planning, scheduling and cost engineering skills.
- Project management principles should also be applied to significant O&M efforts requiring cross-functional participation.
- Formal approval and kick-off of projects/programs should not be permitted in the absence of reasonably firm scope definition and a cost estimate whose quality is consistent with the current design status.

PM knowledge areas and attributes

- The philosophies, principles and methods of cost management that are described in further detail under "Work Management" should be applied in the project environment. This includes the holistic approach, appropriate systems, measures, analysis, reports and corrective action requirements.
- Major components of the work should have their own tailored "cost management plan" that describes the baseline cost, who is accountable and how costs will be managed. Such plans should include the specific actions required of the cost manager and the supporting cost engineer.
- Large projects should contain "exit ramps" early in the job to permit management re-consideration if costs begin to escalate.
- A program of scope control should be in place that identifies scope deviations early, requires analysis of such deviations and the mandatory specification of alternates to mitigate the effects of the deviation.

- The role of quality and its relationship to cost and schedule achievement should be clearly defined and understood by all project participants.
- A process for the handling of contingencies should be defined and the "owner" of budgeted contingency funds for purposes of funding approvals should be identified.
- Project management principles that define requirements for contractor project management programs on "turn-key" projects should be in force.

Organizational culture and capabilities

- The role and responsibility of the project manager should be clearly defined and understood throughout the organization.
- Expectations for project managers should be consistent with the authority and resources given the project manager.
- Project management requirements for project participants should be generally consistent across all projects.
- There should be a clear linkage between project management and the budgeting systems, characterized by input from and feedback to those systems.
- The relative priority of projects and programs should be defined in the planning and budgeting process and, once projects have been approved, assigned and scheduled, those priorities should be moot (i.e., the project manager should not have to compete for resources).

PM applied to program management

- The construction program should have provisions for the collective management of small projects, as opposed to the standard project management approach.
- The project management program should apply to all organizations participating in a project, whether IUSA or contractors.

Liberty undertook the following key activities in evaluating the Companies' gas project and program management against the evaluation criteria:

- Evaluated IUSA's approach to project management, including the PM approach (weak or strong), applicable projects and organizational dynamics.
- Evaluated the quality of the project management and support organizations, including the skills and experience of the key incumbents.
- Evaluated the degree of support given project managers and its consistency with the expectations for project managers.
- Tested the relationships among project managers and the functional organizations and the degree to which the organizations support and are supported by the project manager.
- Evaluated the cost management systems in use for projects and the effectiveness of their utilization by the project managers and the functional organizations.
- Evaluated the quality systems in use for projects and the effectiveness of their utilization by the project managers and the functional organizations.
- Evaluated the schedule management systems in use for projects and the effectiveness of their utilization by the project managers and the functional organizations.
- Evaluated project management expectations and performance in other critical project elements, including safety, procurement, materials management, communications,

contractor interfaces, labor relations, HR, bookkeeping and administration.

- Prepared at least three case studies of actual projects (one <25 percent complete, one in mid-stage and one complete) and determined how project management systems have worked, where opportunities have been taken or missed, and where improvements may be possible. Determined the degree to which the case studies are representative of broad project management performance.
- Evaluated how projects are initially prioritized and then slotted in the budget, and the impact of this decision on subsequent execution.
- Evaluated how initial scope is defined, including its credibility, relative "sanctity" and its ability to serve as a good baseline for control. Determine if there are any propensities to approve and start projects without sound baselines for control.
- Determined the degree to which mechanisms exist to stop, reconsider and, if appropriate, cancel projects that exhibit early out-of-control tendencies. Examined the triggers to alert management to the need for such reconsideration.
- Evaluated how the balance of the construction program (i.e., those projects that do not come under a project management approach) is managed.
- Evaluated how contractors are managed within the context of the project management program, including those with "turn-key" responsibilities.
- Determined how IUSA project managers are expected to balance cost, schedule and quality, among other priorities, and what guidelines, training, policies or other aids exist to help meet this challenge.
- Evaluated how project managers maintain conformance to the project's "intent" with the restraints experienced in day-to-day management (budgets, scope changes, contingencies, design errors, etc.). How is the project manager's ability to stay true to the intent monitored?
- Evaluated the flow of projects from the budgeting process into the project management jurisdiction, including how project budgets are then set (in relation to what is in the capital or O&M budget) and how design intent is maintained.

8. Annual Capital Planning

IUSA's Gas Planning Group develops the capital plan each year based on PSC-mandated programs (leak-prone mains and services), highway-relocation projects, system infrastructure improvements and projected customer growth. A project authorization form and economic model, which includes the initial project cost estimate, is developed by Gas Planning and submitted for all projects and programs greater than $100,000. The project authorizations are approved by the appropriate Level of Signature Authority (LOSA) based on overall project cost.

The Gas Planning Group typically provides the preliminary list of the majority of the projects for the next year to the Gas Design Group four to six months prior to the start of the construction season. Many highway relocation and new customer projects are developed throughout the year, based on input from municipalities and customers. Gas Design then develops the final design of the projects, develops the refined project budget and develops the SAP work orders. Each work order must be approved by the required LOSA based on the final project budget.

All projects with contractor costs estimated at $100,000 or greater are competitively bid, based on company contracting policies and procedures. The Gas Design Group manages the bid process in cooperation with the Strategic Sourcing Group. For contractor costs less than $100,000, previously bid contracts are used to complete the work.

Once all approvals are received and all required permits are received, the project is released by Gas Design to the Gas Construction and Maintenance Group, who assigns the work to an appropriate construction contractor or to an in-house construction crew. Note that generally, over 90 percent of all construction work is contracted, with smaller main related and service projects and regulator station work completed by Company crews. The Gas Construction and Maintenance Group perform random inspections on each project. The Gas Construction and Maintenance Group also monitors project costs and processes all contractor invoices based on the competitive bids received or using pre-established Pay Identifiers (PID's) for each synergy contractor.

Large projects, with the exception of leak prone and highway relocation projects, greater than $1,000,000, are managed by the Gas Planning Group. The Planning Group develops separate RFPs for project management and design work in cooperation with the company RFP process and procedures for each project. Each RFP is awarded based on the standard bid award process. Purchase requests are developed by the Gas Planning Group and approved by the required LOSA. Once approved, a contract is awarded to the successful project management contractor and the design contractor. The Gas Planning Group reviews and approves work as required and coordinates the development of associated SAP work orders for each phase of the work, so that project costs are authorized and tracked appropriately. After the design work is completed and approved, another RFP is developed for construction work and awarded based on the bid award process. The contract Project Manager oversees the construction work with the support of the Gas Construction and Maintenance group or a contracted inspector.

"As-built" drawings are recorded and input into each Company's mapping system. The drawings are developed by Gas Construction and Maintenance or Project Manager and are reviewed and approved by the Gas Design Group prior to final mapping. Gas equipment records developed as part of the work order process are revised by the Master Data Department based on the "as-built" information. The Master Data Department then closes the Work Order upon completion of all work.

9. GBU Business Plans and Vision

IUSA Gas Operations does not appear to have a formal long-term business plan. They do have a five-year strategic plan that lays out a vision, initiatives, and projects but no real detailed plan. The basic part of their plan is to remain either the best or one of the best operators in New York State per the metrics the NYS PSC collects on a yearly basis (damages per 1,000 locates, leaks remaining at year-end, response time to odor complaints, etc.). Before the most recent rate case, both NYSEG and RG&E had a capital program that was designed to maintain the status quo but not make much progress on some urgent and forward looking issues such as obsolete regulators, a GIS system, etc.

The gas operations VP's vision is that the Company will become proactive in replacing leak prone mains and services and drive the leak rate to as low as possible. His vision consists of speeding up the replacement of not only small diameter cast iron and bare steel, but replacing all cast iron and bare steel. When he was in gas operations in NYSEG (when it was a stand alone company), they replaced all of the cast iron and essentially had a low leak rate. When NYSEG purchased Columbia of New York, they instituted a cast iron replacement program. As of July 2011, all of the cast iron in the former NYSEG service territory has been replaced. The same can not be said for RG&E.

The distribution system vision includes improving safety and reliability, and reducing leakage on the entire system. The cost of replacing leak prone mains and services is significant and the mileage in the IUSA system is extensive. Total fulfillment of this vision will require IUSA to:

- Remove the leak prone bare steel mains and services
- Replace the remaining cast iron mains at RG&E
- Upgrade poorly performing and undersized/oversized regulators
- Use non-corroding materials
- Undertake other safety and reliability initiatives as required.

10. 2011 Gas Capital Budget

The 2011 Gas Capital Budget nearly doubled as compared to the 2010 budget. The majority of the increase was a result of the 2010 gas rate case (which covers the gas season from 2011 through 2013). Significant increases in the amount of main and service replacements on bare steel and small diameter cast iron drove much of the increase allowed as part of that rate case. The accompanying table summarizes the budget's main components.

RG&E and NYSEG Capital Spending on Gas Programs ($000)						
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Leak Prone Main Replacement Program	$18,140	$18,073	$18,819	$19,597	$20,409	$95,038
Transmission Mains	$1,879	$1,716	$11,035	$11,366	$11,707	$37,703
Distribution Mains	$3,813	$7,567	$4,659	$4,799	$4,493	$25,331
Gas Service Replacements	$10,729	$11,769	$11,918	$12,062	$12,199	$58,677
Meter Purchases/Installation	$8,005	$8,245	$4,236	$4,363	$4,494	$29,343
M&R / Gate Stations	$1,925	$1,983	$766	$789	$813	$6,276
Highway Relocations	$8,882	$9,149	$5,509	$5,675	$5,844	$35,059
Other	$11,800	$10,629	$21,558	$22,204	$22,871	$89,062
Total	**$65,173**	**$69,131**	**$78,500**	**$80,855**	**$82,830**	**$376,489**

11. Capital Project Case Study

Liberty examined a number of natural gas programs/projects as case studies of IUSA project management. Liberty's review of the 2011 Gas Capital Plan identified three such case studies. One, the Canandaigua CI Main Replacement (NYSEG, Geneva Division), is almost complete; another, the Southwest 60 Expansion is just starting (RG&E); and the third, the Seneca West

Transmission Expansion is in the detailed engineering phase and has not yet started (NYSEG, Elmira Division). Each of these was selected because they met the criteria of having one project that is complete, one that was in progress, and one that had yet to start. They also cover both operating Companies and lie in different parts of the various service territories.

Liberty did not select the ongoing main and service replacements for leak-prone mains and services because these are typically small projects, or are jobs being managed by local operations personnel in addition to their regular work and may not give a total or true picture of the project management capabilities of IUSA.

a. Canandaigua Cast Iron Replacement

This project, the last replacement of cast-iron mains in the NYSEG service territory, removed the low-pressure mains in the downtown of the city of Canandaigua. Approximately 3,000 feet of main were laid (a separate main on each side of Main Street) by a contractor during the spring evening hours. The work progressed from 6 PM until 2 to 4 AM during most weekday nights. Weather was a factor, because this was one of the wettest springs on record in central NY. Because NYSEG does not have a formal project management group, an ad hoc group consisting of the engineering supervisor in the Geneva-Auburn Division and the Operations Manager/Supervisor in Geneva ran this project. They assigned a fitter to be on the job from 3 PM to 11 PM every night that the contractor was working. The fitter also did service work, such as relighting services that had been replaced. NYSEG chose to replace low pressure with low pressure, but upgraded all of the services to 2” in the event that the use of the building changed (restaurants and rental apartment above the store fronts) which could increase gas usage. The project started late due to weather, permits, and late detailed engineering, but there was sufficient time in the scope to ensure that the project completed on time. Initially the project was going to use mostly direct burial but the contractor was able to do some horizontal direct drilling (HDD) which saved both cost and time.

There is no formal project engineering group; therefore, getting formal and final cost estimates can be problematic since changes are incorporated into the costs as they occur. As best Liberty can tell, this project appears to be under run by several hundred thousand dollars, due to changing to HDD installation, splitting some of the restoration costs with the water company. The operations supervisor coordinated with the water company and developed a sharing plan for doing the restoration work where both parties were involved in the street. Having the project completed in less time than allocated (the project started late but ended on time) was another contributing factor. The project is nearly complete with some restoration remains pending direction from the city. Liberty visited the site and discussed the project with an affected property owner who praised the job except for the city’s lack of restoration plans. He said the impact on his business was much less than he anticipated and that the Company kept him informed along with the other store and building owners. The job was scheduled to be completed before the summer tourist season, and that was accomplished.

b. Southwest 60 Expansion

This project is in the southwest corner of Monroe/Livingston County in the RG&E service territory that was previously part of Pavilion Gas. It is about 6 miles of 12” steel distribution main that will cut down the middle of a horseshoe shaped distribution system with Mt. Morris and Geneseo at the bottom. The project started a few days before the Liberty auditor visited the job site. One of the justifications is that near the top of the horseshoe is the Graysville (Dominion) take station, which is out of balance in that it cannot take sufficient gas. Another justification is that the pressures at the bottom of the horseshoe are low in Mt. Morris and Geneseo during the winter. The project allows for additional supplies to be taken and moved to the bottom. A contractor, DDS, is doing all of the work and Gas Operations has an inspector drive by periodically. All of the quality control is being done by the contractor's QC group and IUSA does not intend to monitor the contractor other than periodic visits by a roving inspector. Although the job is fairly simple, it was noted that the pipe handling by the trucking company was not good; it was dragging metallic chains across the fusion bond epoxy coating. Inspection of several pipe lay-down areas showed considerable coating damage and the two sticks of pipe already in the ditch did not show any coating repairs. Liberty questioned the coating holiday detection (presence of defects) and repair requirements. The Company reported that each piece of pipe was to be electronically inspected (jeeped) prior to being placed in the trench and that DDS was to repair all coating holidays[2] (defects).

c. Seneca West Transmission Expansion

This project will install a new gas transmission extension from the previously owned Seneca West Pipeline to a new gate station located in Horseheads, NY just north of Elmira. The new transmission main will follow an existing pipeline and electric right of way east from the Seneca West Pipeline and then south to the new gate station which will be located adjacent to an existing gate station. The rational for the pipeline is to provide additional supply to the Elmira area from the Seneca storage field in which IUSA retains a partial interest (at one time NYSEG owned both the Seneca West Pipeline and the Seneca Storage Field).

IUSA does not have the resources to design nor manage a project of this size. It has contracted out the engineering and detailed design to CHA (Clough Harbour & Associates) in Albany and TRC Companies, Inc. for oversight on behalf of the owner (IUSA). TRC has retained a former NYSEG employee to handle this assignment. This provides someone familiar with the Company, the pipelines being impacted and area (this individual was out of the Binghamton engineering office).

The current project timetable calls for detailed engineering to be underway now (which it is), securing rights-of-way (also ongoing) and preparation of bid documents for procurement and construction (also underway) and development of the Article 7 application (due to be sent to the NYS PSC in the fall). This project has been proposed several times in the past; each time the cost has been estimated. The latest cost estimate is $5,792,000 with the bulk of the costs to be expended in 2012. At this time IUSA is not sure if it will use employees to perform the project management or hire an outside consultant to do that function (with the current staffing levels an O/S consultant is probably the only viable alternative).

Liberty verified adherence to many of the project management process items in the written procedures during these case studies, including:

- Lessons Learned process

[2] See IR #142 for more details on the pipe handling

- Scope preparation and control process
- Schedule preparation and control process
- Construction Work Estimate (CWE) preparation and monitoring
- Bid check reviews
- Formal status reports
- Minutes of meetings
- Purchase Order Change Request (POCR) process and control
- Contractor Evaluation Report process
- Environmental Health & Safety plans.

Where Gas Engineering is working on large discrete projects they have stated that they will use outside resources to make up for the deficiencies that they have in their organization. Although they have a recently organized Project Management group, they do not have any project managers on board to assist in large scale projects.

12. Gas Vegetation Management

All gas transmission line right-of-way (ROW) is cleared annually. Distribution ROW is cleared as indicated by leak survey requirements. RG&E relies on one vegetation management contractor while NYSEG has as many as four under contract, depending upon location. Additionally, RG&E uses three to five field personnel (including supervision) during the inspection process while NYSEG uses two to three.

Prior to 2011, NYSEG did not have a formal gas vegetation management process; vegetation management was done as needed. At RG&E until 2009, gas ROW clearing was done in conjunction with the electric vegetation management process and budget.

For the period September 2010 through August 2011 IUSA spent $360,688 on gas vegetation management (budget of $363,000). From September 2011 through August 2012 IUSA has budgeted $367,000 for gas vegetation management. As of mid-October 2011, IUSA had spent $44,916. IUSA appears to be on target with its gas vegetation management program and spending.

C. Conclusions

1. IUSA does not have a workable project management function in either gas operating company. *(Recommendation #1)*

IUSA has formed a project management group within the gas engineering organization, but this group does not have any individuals who can run a large project except for the group's manager, who is also helping the new gas engineering manager and who also is running the gas planning function. The early retirement programs in 2010 and other personnel reductions under the prior owners have depleted the engineering staff to the point where there are very few individuals with any gas engineering experience.

The engineering staff relies on gas operations inspectors to track and report on project field progress as the established business practice. IUSA does not have a working project management group in the gas business unit. Because of the these limited resources, the operations group functions as the project management group on smaller and routine projects such as main extensions, service replacements, leak prone main replacements, etc. The operations group has also had a significant reduction in both management and union staffs (management and union voluntary early retirement in 2010 for NYSEG, management early retirement for RG&E in 2010 and a planned early retirement plan for RG&E union workers in late 2011) and thus may be hard pressed to provide inspectors and project management functions on a constant basis for the increase in capital work starting in 2011.

2. **The Company cannot demonstrate that the current system of using outside engineering resources is as labor saving or cost effective as originally proposed.** *(Recommendation #2)*

The lack of engineering resources in the RG&E unit has led management to outsource some of the gas engineering design functions. This outsourcing is designed to reduce the work load on the existing staff, while enabling the Company to expand the capital expenditure program to mandated levels per the recent rate case. Many of the jobs historically done by Company engineering staff have been contracted to outside consultants to perform the detailed design and develop the lists of materials to be procured for each project. The Company does have the existing staff do the actual purchasing of the materials in order to ensure that the proper material is purchased. This use of Company engineering staff to review and procure materials is time consuming and a significant amount of the expected savings in time may not be occurring.

3. **Benefits from the increase in capital funding are jeopardized by the lack of engineering and project management resources at both IUSA and their contractors.** *(Recommendations #1 & #2)*

The gas management of IUSA is having problems with the increased work load resulting from the increases in the capital program. Moreover several of the contractors that IUSA uses to perform the work are also having issues with securing sufficient experienced staff to complete the work. Many of the experienced contractor workers needed to complete the large increase in the annual capital expenditure program are now working on natural gas exploration in Pennsylvania (and expected soon in the southern part of New York State). These gas wells and related pipelines are expected to be in construction for the next several years at a minimum and thus many experienced workers are no longer available. In the Rochester area, one contractor has been shifting workers from the Albany area in order to complete assigned main and service replacements.

4. **IUSA has a minimally-staffed gas QA/QC function monitoring and overseeing its capital improvement and maintenance program work.** *(Recommendation #3)*

Quality Assurance (QA) comprises the systematic monitoring and evaluation of the various aspects of a project, service or facility to maximize the probability that the production process is attaining standards of quality. Quality Control (QC) encompasses the observation techniques and activities used to fulfill requirements for quality. The end product should be “fit for purpose” (suitable for the intended purpose) and "right the first time" (mistakes minimized or eliminated). QA/QC covers assurance and inspection of the quality of received materials, installed components, and services related to production. The QA/QC program envelopes all work performed by internal work force and contractors.

RG&E and NYSEG have always emphasized quality performance in their daily activities. The Gas QA/QC Program has been developed to ensure that activities, as defined within the program scope, are being performed correctly and in conformance with applicable requirements. The program is designed to assure the safe operation of gas transmission and distribution systems by meeting the requirements of Title 16, New York Public Service regulations, Parts 255 and 261; and Title 49, Code of Federal Regulations, Part 192.

The Gas QA/QC organization is responsible for performing audits and inspections of activities affecting the safe operation of gas transmission and distribution systems. Gas QA/QC personnel have sufficient authority and organizational freedom to identify quality problems; to initiate, recommend, or provide solutions; and to verify implementation of those solutions. These personnel report to a management level such that this required authority and organizational freedom, including sufficient independence from cost and schedule when opposed to safe considerations, is provided.

The Gas Operations QA/QC staffing for NYSEG and RG&E was as follows:

Historical QA/QC Staffing				
Position	**2008**	**2009**	**2010**	**2011**
Supervisor - Gas Engineering	2	2	1	0
Lead Analyst - Gas Engineering	3	3	1	2
Total	5	5	2	2

The Gas QA/QC Program addresses the following attributes:

- Management Oversight
- Organization
- Design Control
- Procurement
- Document Control
- Control of Materials, Parts and Components
- Special Processes
- Inspection
- Control of Measuring and Test Equipment
- Inspection and Operating Status
- Nonconforming Materials, Parts, Or Components
- Audits
- Training
- Corrective Action Records

Gas QA/QC personnel are responsible for coordinating the formulation of the Gas QA/QC Program and for verifying its implementation through periodic assessments. RG&E and NYSEG personnel and contractors are responsible for implementing the Gas QA/QC Program in accordance with the requirements of the Gas Operating & Maintenance Procedures Manual, and the Gas Construction Standards and Installation Manual. The Gas QA/QC personnel also serve as primary liaison with DPS staff during gas emergencies.

The following functions have been identified as affecting quality, and will be subject to periodic audits and surveillances:

- Operator Qualification
- Corrosion Control Programs
- Facility Damage Prevention
- Construction Activities impacting Cast Iron Facilities
- Facility Mapping
- Facility Patrolling
- Material Procurement and Handling
- Personal Protection Equipment Usage/Safety
- Emergency Plans and Effectiveness Drills
- Bare Steel/Cast Iron Facility Replacement Programs
- Pressure Control
- Valve Inspections
- Mercury Regulators
- System MAOP
- SCADA Operations
- Leak Classification/Repair Activities
- Service Line Valves & Regulator Vents
- Inactive Services
- Utilization
- Document Control
- Construction Inspection
- Integrity Management Program.

5. IUSA has maintained an excellent compliance and safety record to-date.

The NYS PSC collects a series of safety and performance metrics for all of the gas utilities across the state on a yearly basis. IUSA (gas) has an exemplary compliance and safety record to-date. Both Companies have met or exceeded all gas safety performance goals during 2005 – 2010.

In addition, the IUSA gas companies also repair all classes of leaks rather than only repair the mandated classes. This additional work ensures that the respective gas systems are operated as safely as possible and that greenhouse gases are minimized along with the safety threat of gas leaks to the general public and customers.

NYSEG and RG&E were the only companies in NY that have implemented a bare main isolation program (10 miles per year) to extend the life of leak prone pipe.

Over the past five years (2006-2010), each company has also met or exceeded the PSC target for emergency response. In addition, RG&E has consistently led all NY utilities in response to calls in <30 minutes.

NYSEG and RG&E have also made significant progress in reducing third-party damages.

D. Recommendations

1. **Formalize Gas Project Management Organization & Process by staffing a Gas project management group with experienced individuals to manage all of the capital program projects, even the small main and service replacements. Additionally, the Companies should formally document project management procedures in a Project Management manual.** *(Conclusion #1 & #3)*

The 2010 reorganization of the gas business unit produced a gas planning and project group. Since that time the NYS PSC allowed significant rate and capital expenditure increases for both operating Companies. The new capital plan is more than a 50 percent increase in the rate of spending. However, IUSA has not staffed the new planning and project group to meet this increase, rather relying on contractors to provide design engineering and project management services.

Engineering and design contractors have been used for gas related work since 2010, primarily at RG&E. The Voluntary Early Retirement programs in 2010 impacted RG&E Gas Engineering staffing levels resulting in a reduction of nearly 65 percent (from 14 to 5, 2 of which are new). Approximately 70 percent of design work is currently performed by contract engineering services at RG&E.

Contractor engineering and design are only used for special projects at NYSEG, such as the Seneca West Interconnection Project. Otherwise, all design work is completed by NYSEG personnel. However, a plan is currently being explored to increase the use of contracted project management and engineering services for both NYSEG and RG&E to supplement current Gas Design and Delivery staff.

Engineering has recently issued an RFP for project management services to support engineering and enhance project management for both NYSEG and RG&E for large programs and projects such as leak prone main replacements and regulator station work. This RFP is intended to enhance management of programs including oversight, coordination, schedules, and cost control from design through final construction. However, there have not been any business case studies to justify the use of external project management in place of hiring internal project management personnel.

Large projects (with the exception of leak prone and highway relocation projects) greater than $1,000,000 are coordinated by the Gas Planning Group. The Planning Group develops separate RFPs for project management and design work. Once approved, a contract is awarded to the successful project management contractor and the design contractor. The Gas Planning Group reviews and approves work as required and coordinates the development of associated SAP work orders for each phase of the work. Once the design work is completed and approved, another RFP is developed for construction work and awarded based on the bid award process. The contract Project Manager oversees the construction work with the support of the Gas Construction and Maintenance group or a contracted inspector.

All engineering, design, and portions of the maintenance work are managed by the Gas Design and Delivery Group. Leak surveys, construction, portions of maintenance work and locating services are managed by Gas Operations. Our review of projects documented a variety of project management approaches in use and no consistency between the Companies. There is no consistency in capital cost monitoring, reporting, and review. Additionally, there is no Project Management Procedures Manual for Gas work.

The levels of internal project engineering and project management personnel do not appear to be sufficient for proper project review and monitoring, forcing a heavy reliance on operational personnel or contractors for project review and monitoring. A loss of project control and maintenance of existing standards and specifications is a concern.

Cost

IUSA should appropriately staff a Gas Project Management organization with internal or external resources to enable it to function as intended. Analysis should be conducted to determine the appropriate number of project managers to add to the organization. The annual average in-house Project Manager salary with benefits is $124,000. Assuming IUSA adds two project managers to staff a project management organization, this would result in labor costs of $248,000 annually.

Additionally, IUSA should develop a Project Management Procedures Manual to formally document the project management process and expectations for Gas project management work.

Savings

The benefits for this recommendation cannot be practically quantified. Project management planning is a basic productivity improvement process. Project management procedures are designed to improve the project delivery process. The benefits of improving the project management procedures are known to be:

- Decreased project costs
- Improved project schedules
- Improved employee productivity
- Improved budget monitoring.

2. **Review manpower requirements to meet the capital and program requirements within the gas organization and make changes accordingly.** *(Conclusions #2 & #3)*

The capital program at IUSA doubled in 2011 while the engineering staff in the gas business area has been reduced by more than 50% (for RG&E and a lessor amount for NYSEG). The gas engineering staff at RG&E’s Scottsville Road facility went from 14 experienced engineers to 5 engineers, with only 3 having significant experience.

As discussed in an earlier conclusion, there are essentially no project engineers or project managers on the staff of the IUSA gas business unit. The project function is currently handled by gas operations personnel or gas engineering personnel on an ad-hoc basis, in addition to their other responsibilities.

Gas operations personnel such as fitters or foremen handle field inspection of jobs. Since there are multiple jobs in progress at the same time, most of the inspectors do a ‘drive by’—they drive to job site, ask the contractor’s foreman about head count and any other issues, and drive to the next job. The time spent on any particular job is a function of the number of jobs in progress, the problems encountered, and the time to get from job to job. At best, the inspectors try to visit each of the jobs daily, but in many situations this is not possible.

Another manpower shortage is apparent in the engineering department. Many of the new jobs are being designed by outside engineering design firms that must learn the IUSA gas system and then design the infrastructure projects. The engineering contractors are charged with the detailed engineering and providing procurement lists for IUSA gas engineering. Since some of these individuals may not be familiar with the location of the mains and services, there may be a steep learning curve. Company engineering staff must then review procurement lists, make any necessary changes, and write the requisitions, since contractor engineers cannot order materials. Additionally, when the materials are delivered, gas engineering personnel must ensure that the material is delivered to the correct location/job and verify that the materials received are sufficient to complete the project. This work is quite time consuming and creates an additional burden for company engineering personnel.

Additionally, because of the reduced gas engineering staffing, many of the projects for the current year are not fully designed until much later in the year. This increases the risk of job slippage and overages.

With the increase in capital work, not only are IUSA personnel being challenged to complete all of the funded work on time but contractors are also challenged. IUSA uses several contractors throughout the service territory and each of them has found adding skilled gas workers a challenge because of the large increase in gas exploration and gas pipeline work in the Marcellus Shale area (currently in Pennsylvania and West Virginia but soon to start up in southern New York).

If IUSA continues to have an aggressive capital program to reduce leak prone mains and services and upgrade the gas infrastructure, it needs to evaluate the need to supplement staffing in the project management group, engineering, or gas operations to properly design, inspect and manage these capital projects.

Cost

IUSA should conduct further analysis to review manpower requirements, including engineering design, project management, and construction, to meet the capital work schedule over the next five years in light of diminished internal resources and the lack of available qualified contract engineering resources. IUSA should be able to conduct this analysis with existing personnel, resulting in no additional resources.

Savings

The savings from this recommendation are not quantifiable at this point. Liberty expects that a revised staffing approach can minimize overtime requirements, especially at year-end. Additionally, review and evaluation of in-house resources may also mitigate schedule slippages and cost overruns.

3. Staff QA/QC to support an effective and functioning QA/QC program for all Gas projects and programs. *(Conclusion #4)*

IUSA should appropriately staff the existing Gas QA/QC group to support an effective and functioning QA/QC program for all projects and programs.

The major quality assurance functions are to assure that an appropriate quality assurance program is established and effectively executed, and to verify, such as by checking, auditing, and inspection, that activities affecting quality have been correctly performed in accordance with procedures and regulations.

This success is due to IUSA having a sound QA/QC Program. With the reduction in staffing level down to two for both companies, Liberty wants to caution IUSA to guard against complacency. Once the program deteriorates, it will take a long while to recover.
IUSA should appropriately staff the existing Gas QA/QC group to support an effective and functioning QA/QC program for all projects and programs. NYSEG and RG&E together performed over $40 million of physical work (in-house and contractors) in 2010. A well functioning quality assurance program must be in place to support an effective integrity management program.

The responsibilities listed above are very extensive. It is inconceivable to conclude that the QA/QC Program can be maintained with just two persons between the two Companies. We recommend the Company perform a thorough evaluation to see if it should return to the previous QA/QC staffing levels.

Cost

IUSA should fill the QA/QC supervisor position as soon as possible. The estimated costs for this position is $75,000 without benefits. Additionally, IUSA should appropriately staff the Gas QA/QC organization to enable it to function as intended and described in the QA/QC Operating Manuals. The annual average salary for a Lead Analyst is $50,000 without benefits. Analysis should be conducted to determine the appropriate number of lead analysts to add to the organization. Assuming IUSA adds two lead analysts and one supervisor to the QA/QC organization, to reach 2008 staffing levels, this would result in costs in the range of $175,000 annually (without benefits).

Total ongoing labor costs for this recommendation approximately $175,000 (plus benefits).

Savings

The savings from this recommendation are not quantifiable at this point. Liberty expects that the Companies will benefit tremendously from an effective and functioning QA/QC organization supporting Gas Operations. These benefits include increased safety for customers, the public, and employees through proper inspection and oversight of gas programs and projects. Additionally, IUSA should realize benefits through reduced contractor and company crew rework; however, Liberty cannot estimate these benefits at this time. Proper reporting and analysis within the QA/QC department should enable these savings to be captured and reported.

Benefits

Improvements to reduce wasted effort mean that the effort saved can be utilized on more productive work. The financial performance and productivity of the company are, therefore, able to improve as a result of the investment in an effective quality assurance/quality control system. The benefits of an effective QA/QC program are summarized as follows:

- Assurance that property units are installed in accordance with the design drawings and specifications
- Reduction in loss of time due to rework or ineffective and inefficient practices
- Increased reliability of the end product
- Motivating employees to provide higher quality service
- Problems identified and resolved in an open manner
- Increased confidence that controls are in place and the risk of error is reduced
- Assurance that Company policies and operational procedures are being followed
- Enhanced reputation in the business and government community attributed to the Company that prescribes, demonstrates, and enforces high standards of quality control in an environment of self-regulation.

Work Management

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XIII. Work Management

Liberty has evaluated the elements of work management associated with the major physical work conducted by the Company with a particular emphasis on cost and effectiveness. We divided the evaluation into four sections:

A. Cost Management
B. Work Planning
C. Resource Management
D. Performance Measurement.

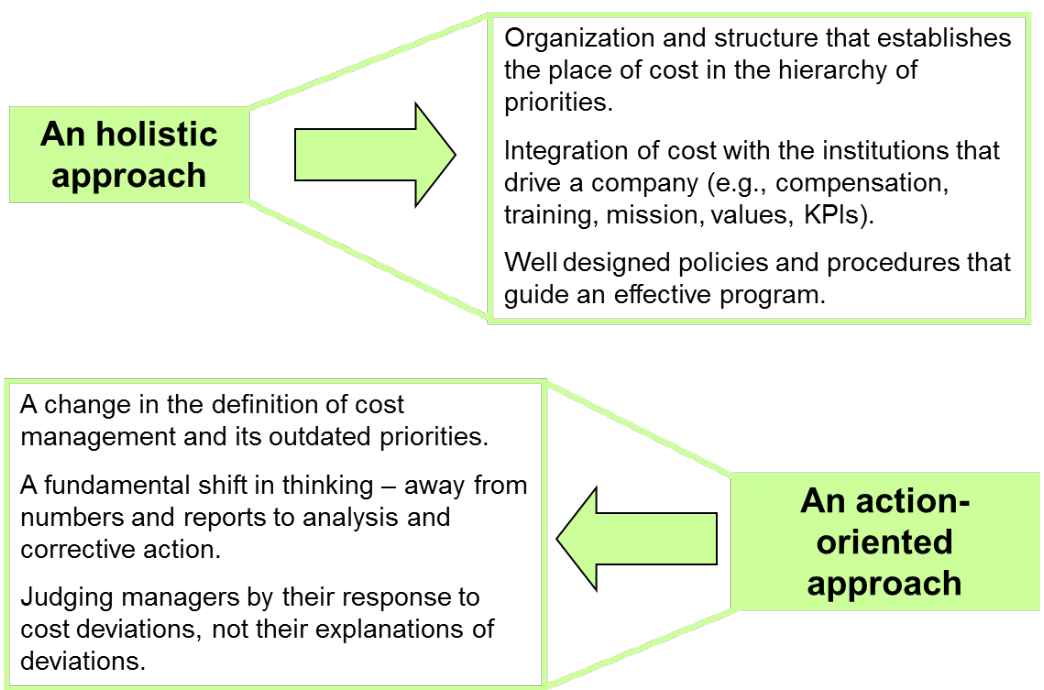
Overall, our evaluation concluded that implementation of an expanded view of cost management, which we term holistic cost management, will make IUSA performance more effective and cost efficient.

A. Cost Management

1. Background

Liberty discussed with IUSA a fundamentally different option for cost management, one which we defined as a holistic approach to effective cost management. Firms employing this approach effectively have begun with a shift in thinking at the policy level, establishing cost as a priority, designing an organization and structure to further cost effectiveness and integrating cost into the other management systems of the Company. A shift in thinking also occurs at the implementing level, as the organization moves away from a more narrow focus on numbers and reports to an expanded array of analysis and action.

Cost Management Approaches



IUSA management responded positively to this initiative, and has already taken steps to make it a reality. A team of managers, headed at the executive level, is in place and advancing the holistic approach at this time. As a result, we have provided a limited number of formal recommendations, in the recognition that the Company, if committed to the holistic approach, will find and implement the best solutions for its circumstances. We have provided recommendations on the essential components of the holistic approach, buttressed by options that IUSA's team may wish to consider in building its approach and supporting program.

The holistic approach may be viewed by some as a change in the definition of "cost management." For example, traditional (and we believe now dated) definitions define cost management essentially in terms of "cost accounting." Others consider cost management to comprise the process whereby companies use cost accounting to report or control the various costs of doing business. Neither portrayal is sufficiently robust to fill our definition of cost management, which we express as:

> *A process through which professionals, knowledgeable in both the work being performed and cost-related skills, analyze the anticipated and actual execution of the work in a way that permits them proactively to improve efficiency, with the ultimate objective of optimizing expenditures.*

The criteria by which Liberty evaluated cost management include:

- The relative "place for cost" in the hierarchy of priorities (for example, with safety, quality, and schedule) should be clearly defined so as to be understood by all employees.
- Costs should be collected consistent with the Work Breakdown Structure (WBS) and be structured to facilitate analysis.
- Reports on work force performance should relate costs to production and achievement of other job objectives. Credible analysis should be included in all management reports, and that analysis should include corrective action recommendations for cost deviations.
- A management process should be in place that forces response to cost deviations.

2. Findings

a. Cost Management in the Corporate Hierarchy

We judge the priority of cost management in a utility by not just its words but also by its actions. Clear statements and policies by management help to determine where cost management resides in the hierarchy of priorities. More importantly, management's actions, in terms of resources assigned, performance measures, ties to compensation, response to issues and other demonstrations of support, have much more significance.

A minority of companies specifically names cost management as a corporate priority. Other directly or indirectly related phrases, such as effectiveness, efficiency, budget, competitively priced, earnings and return, appear instead. This is the case at IUSA, as shown by the IUSA Strategic Plan 2011-2015, which helps to define and communicate the cost culture in the Company. Cost dimensions of key elements of that plan are listed below:

(1) Mission – No mention of cost

(2) Strategic Planning Principles - Safe, reliable and cost-effective customer service; to improve performance and efficiency
(3) Priorities and Goals – Financial growth; to improve company bond rating
(4) NYSEG/RG&E Strategic Priorities – No mention of cost
(5) Functional Area Strategic Priorities:
   - Electric Operations – To optimize capital spending; to improve storm recovery efficiency
   - Gas Operations – Fiscal management; to achieve benchmark level of operational excellence
   - Business Transformation – To implement best practices using benchmarking; to increase process and performance efficiency; financial growth
   - General Services (Fleet Management) – To maintain safe, reliable and cost-effective vehicles & equipment
(6) Functional Area Initiatives & Generation 1 (2010 – 2011) Projects
   - Electrical Operations – Ongoing measurement and continuous process improvement; to develop scorecard metrics for storm management and historical cost trends; to optimize resource scheduling effort; to optimize capital spend; to utilize automation for best practices
   - Gas Operations – Fiscal management; to maximize efficiency by improving leak survey process; to develop better business performance metrics for regional benchmarking; to utilize automation for maximizing efficiency; to reduce third party damage costs
   - Business Transformation – To deploy unit cost for major business processes; to develop benchmarking plan; to develop operating reports; to develop on-going process to measure and audit the cost savings of continuous improvement initiatives
   - General Services (Fleet Management) – Fleet right-sizing; to develop standardized maintenance to reduce O&M costs; fleet training program to maximize productivity.

This Strategic Plan provides the most recent statement of leadership's intention that cost, as listed in its various related forms, be an integral part of the hierarchy. At the corporate level, there is recognition that cost effectiveness operates as a priority in establishing strategic planning principles. There is, however, no mention of cost management in the mission statement, goals, and strategic priorities. As we moved down the organization to the functional areas, we found various initiatives and projects (recently started) to make improvement.

As in many firms, cost management at IUSA does not operate as a structured program or discipline. Instead, again typical of many companies, it is presumed to be an ongoing responsibility of managers, with the further assumption that the requisite skills and capabilities are inbred into all managers. The prevalence of this tendency in the utility and other industries means that IUSA does not fall outside the spectrum of mainstream experience in this regard. Nevertheless, we believe that there is a large opportunity for enhanced cost management if IUSA, like many of its compatriots can get past the reliance upon implicit, rather than structured, supported, and reinforced approaches.

b. IUSA Cost Program

i Budgeting Process

IUSA's Cost Program consists of essentially the budgeting system. The annual budget provides the control base line. IUSA monitors the monthly and year-to-date budget variances throughout the year, versus the O&M budget. The capital budget is monitored to ensure the expenditure level is achieved. Any shifting from O&M to Capital (called labor movement allocation) is considered very favorable by the Company.

The annual budgeting process is simple and straightforward. The budget is categorized into O&M and Capital. The two categories are further broken down into staff cost and outside service cost. The payroll cost, provided to each department, includes assumption of staffing changes for the budget year. The departments then determine the percent of labor that will be spent on capital projects or in other functional areas. Outside service cost, such as contractors and material costs, are evaluated based on prior year expenditure level and various adjustments, such as regulatory obligations, contract negotiation changes, escalating factors, and cost efficiencies realized. Overheads and shared service costs are allocated based on various predetermined criteria. Adjustments will be made after upper management reviews the preliminary budgets.

The base budget of each department consists of primarily planned work, but also includes estimated levels of emergent work, based on historical information, that may occur. IUSA, however, does not build budget based on the volume of work even for measurable and repetitive work items. Hence, there is no incentive to track work units accomplished or productivity rates. Significant incidents of emergent work, such as storms, are handled by special accounting assigned to capture costs for each incident and may result in budget revisions.

The Capital Delivery Group is currently developing a Project Management Manual. The manual includes is a chapter on Cost Management. It includes a section on Cost Control. Details of the contents are not available at this time. It is reasonable to assume that the approach is supposed to apply only to Electrical Operations capital projects.

ii. Cost Reporting and Cost Analysis

Most IUSA reports designed to monitor the capital or O&M budgets are issued on a monthly basis. Some have budget variance explanations; others do not. There is little cost analysis and, in general, the reports do not focus on timely corrective actions. All the cost reports examined follow this same pattern (*i.e.,* none have recommendations for corrective action):

- Net Income Variance Summary: variance explanation (yes)
- Gas Operations Monthly Corporate Report: analysis (no)
- Electric Operations Budget Variance Report: variance explanation (yes)
- Year-end Forecast Update Report: analysis (no)
- Capital Expenditure Summary Report: analysis (no)
- Year-end Job-hour Comparison Report: analysis (no)
- Performance Management Report: variance explanation (yes)
- Gas Operations Year-end Budget Variance Summary: analysis (no)

In defining IUSA's de facto, basic approach to cost management, we draw a distinction between programs oriented to the collection, monitoring, and reporting of costs and those oriented to the analysis and management of costs. Focusing on the latter is a key driver of effective cost management, yet it is a distinction that is unknown in many organizations. The former approach is:

- Accounting oriented
- Focused on historical performance
- Conducted at arm's length from the work
- Has an end product of numbers and reports.

Financially oriented staff generally has the skills and capabilities for the tasks that the former approach entails. The function of staff in that approach is largely one of oversight. Their key deliverable is information for the accounting system and its financial needs and for managers to fulfill their cost management responsibilities.

The alternate approach, a hallmark of holistic cost management, takes a different view of the challenge. It can be characterized as:

- Technically oriented
- Proactive, and focused on future costs
- Conducted by participants within the work process
- Has an end product of action to produce cost benefits.

This latter approach requires different disciplines altogether. The focus of the work, the deliverables, the motivation, the skills, the tools required, and management's expectations differ greatly. The second, more robust, approach does not replace but supplements the first approach, which does fulfill important needs.

Oversight is generally:		Control is generally:
After the fact	⟺	In process – real time
Reactive	⟺	Proactive – anticipatory
Reporting	⟺	Managing
Arms length	⟺	Participative
Focus on numbers	⟺	Focus on analysis

The second approach is a key element of holistic cost management, and defines the effort as action-oriented and results-driven.

IUSA's current program, like most utilities, is heavily weighted towards the first approach. This is evidenced by a number of observations:

- The management reports have some charts and tables, but usually contain little in the way of analysis.
- Discussion of cost data, where it exists at all, usually focuses on what happened, but seldom seeks the "why" (root causes) or how to mitigate similar situations in the future
- Performance metrics measure many criteria, but not productivity
- The only measurement of cost at any level is budget monitoring

- The existing tools (*e.g.*, performance indicators, productivity reports, cost analysis) focus on budget adherence
- Cost-effectiveness is not a focus
- Cost reports are issued for budget status purposes with limited documentation on any resulting management actions
- The description of cost-related function or positions contain words like “financial” or “fiscal,” suggesting that the regular mode of operation is one of oversight and not cost control.

c. Skills and Capabilities

Four financial personnel in the Controller’s group coordinate with 75 people in the functional areas of RG&E and NYSEG to prepare the annual budget, and to submit explanations and analyses for the monthly variance reports. Each functional group also has an assigned Control Liaison (seven individuals in total) to aid in budgeting and variance analyses. Most of these people in the field are planners or administrative clerks. They are involved in preparing the work package information and they are familiar with the field operations and personnel performing them. They generally are prime candidates for training as future cost professionals to implement a holistic cost-management program.

IUSA’s present cost oversight personnel generally possess financial backgrounds. They can also be trained to become cost professionals by enhancing their cost analytical skills and by acquiring appropriate field experiences.

The Company has no in-house cost engineering expertise. It will need to acquire from external sources a core body of cost engineers and cost analysts to secure required, state-of-the-art expertise. It will also need to establish a cost management training program to teach the candidates and all key functional area managers the essentials of effective cost control.

Our recommended approach gives support personnel an important role in stimulating management action. Their analyses have to be accurate, insightful, reasonable, and convincing, in order to motivate management to corrective action. Cost-support personnel must therefore have a strong understanding of the work being measured, and must be able to detect problems, understand root causes, and propose solutions. In order to do this, they must also have strong cost-skills, which include the ability to accurately translate the data into real conclusions and actions.

Cost support personnel must operate close to the working groups and their management. These support personnel should serve work-group managers directly, and remain close enough to the physical work to understand it, analyze it, and have credibility with those responsible for work performance.

Systems changes need to focus on their applications. Data outputs and reports should not be an end in themselves, but rather a means to improved results. The notion that a cost report is a legitimate deliverable in its own right should be rejected, and replaced with the delivery of insightful analysis, effective recommendations, and plans for improved results.

3. Conclusions

1. IUSA's culture comports with more traditional, but not holistic, notions of cost management. *(Recommendation # 1)*

IUSA management has defined cost-effectiveness as part of its corporate strategy, but the formal supporting structure and program are not yet in place to allow that priority to play out in day-to-day operations, even though at the functional area level there are some objectives of efficiency and improvement. Additionally, organizational ownership of and responsibility for cost management are not clearly defined.

2. The existing SAP system has the ability to collect adequate and relevant cost information for current budget-management needs.

SAP dictates cost information in its multiple modules to flow and be collected in uniform and consistent manners. The cost information is as comprehensive and as accurate as it is intended.

3. Work force management reports include many charts and tables, but contain little analysis or recommendations for dealing with cost variances. *(Recommendation #1)*

The existing tools focus on budget adherence. Some reports do not even offer explanations of obvious problem areas. Cost analysis usually gives explanations of the areas where variances occurred, but seldom seeks the root causes or provides recommendations on what corrective actions are required or how to mitigate similar situations in the future.

4. IUSA's approach to cost management is similar to many other utilities, in that it is financially-oriented and focused predominantly on monitoring and oversight. *(Recommendation #1)*

There are many objectives for collecting cost information. Some are mandatory; *e.g.*, to meet regulatory or other standards or to fulfill basic responsibilities of the business. Liberty therefore does not intend criticism of efforts that we characterize as monitoring and oversight. Rather, the point is that those activities are necessary but insufficient to fully meet the demands of effective cost management.

5. The strengths of IUSA work management practices can help to form the foundation of an effective cost management system. *(Recommendation # 1)*

Our analysis of IUSA's work management practices versus our evaluation criteria produces generally high marks in some areas that comprise good building blocks for a holistic cost management program:

- Basic work planning that facilitates efficient field production
- Cost-effective fleet management
- Effective field supervision, which can provide good input and recommendations
- Good training programs to develop a productive work force
- High-quality safety programs that provide a desirable work environment
- New continuous improvement program that focuses on cost savings
- Fairly extensive performance measures (with the exception of productivity)
- Comprehensive financial cost collection

- Sound budget monitoring practices.

A strong foundation appears to be in place in terms of priorities and motivation. Adding the ingredients recommended here to an enhanced cost management program has the potential to make IUSA more cost-effective and to produce tangible savings for the benefit of customers.

6. **The size of the current IUSA's cost support staff is small and its primary responsibility is to develop and maintain the annual budgets; cost analytical skills and cost control capabilities are lacking.** *(Recommendation # 1)*

IUSA has some capable people in the office as well as in the field, and management has demonstrated the willingness to migrate to a stronger cost-management culture. The necessary cost management capabilities of all the key individuals can be developed and the skills sharpened as the Company evolves to an expanded view of cost as suggested under holistic cost management program.

4. Recommendations

1. **Implement a holistic cost-management program.** *(Conclusions #1, 3, 4, 5, and 6)*

IUSA management has defined cost-effectiveness as part of its corporate strategy, but the formal supporting structure and program are not in place yet to allow that priority to play out in day-to-day operations, even though at the functional area level there are some initiatives on efficiency and improvement. Liberty identifies the following cost management improvement opportunities:

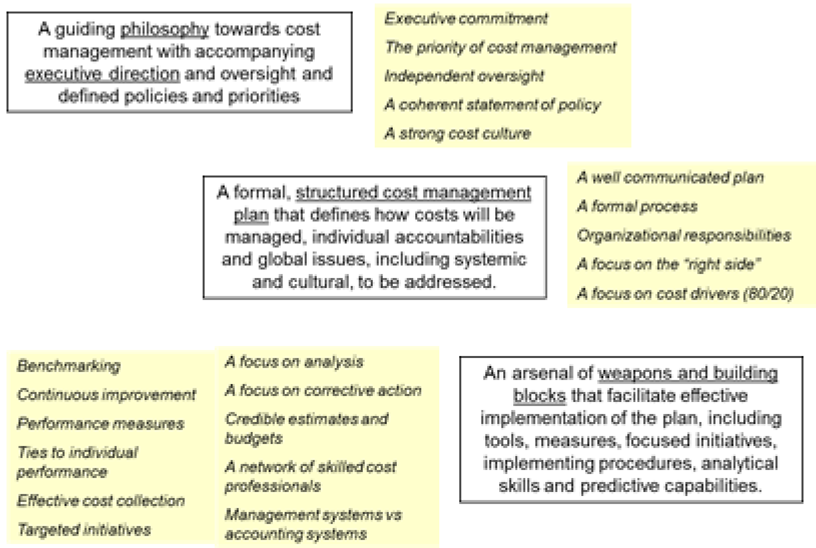
- Cost and productivity management is not fully part of the culture
- Organizational ownership and responsibility for cost management not clearly defined
- True measures of productivity are lacking
- Benchmarking and comparative analysis is lacking
- Need to shift from reactive reporting to proactive analysis and root-cause determination.

Liberty introduced the holistic cost management recommendation as a strawman to IUSA, along with a supporting cost-management framework. The Company responded positively to this initiative, and has begun steps to make it a reality. A team of managers, headed at the executive level, is in place and advancing the holistic approach at this time.

The essential components of the holistic cost-management program toward which our strawman directed IUSA are:

- A guiding philosophy
- A formal, structured cost management plan
- Building blocks of comprehensive supporting capabilities.

A Holistic Approach



Our recommendation for a holistic approach to cost management begins at the executive level, where management sets a foundation with clear direction. This direction communicates a guiding philosophy on how cost management fits in the Company's mission and strategy. It also establishes where cost falls in the hierarchy of priorities. In most companies, this will not be at the top, yet it is important for employees to understand how it does rate. Ignoring the question reduces effectiveness and makes the challenge of balancing cost against other priorities that much harder for managers.

The guiding philosophy will provide direction on management's expectations. It will define policies and priorities for employees. It will also put in place appropriate oversight mechanisms to assure executive management that the philosophy and its accompanying policies are being aggressively implemented.

The second key element of design is a formal, structured cost management plan, or set of plans. Such plans define how an organization will carry out the cost management function. It will define how costs will be managed, the organizational approach to be used, accountabilities, and any specific issues, including systemic or cultural cost issues that must be addressed.

The presumption that cost management is a naturally acquired skill inbred to all managers is wrong. The plan helps educate managers and support personnel on the actions expected of them and how the cost management system is intended to work. It will not be a general document, and the plan for one organization is unlikely to serve another.

The final element is the set of tools to be used in implementing the program. These are the building blocks that bring the philosophy and plan to life. They include the cost tools and reports that organizations traditionally use; but these tools are simply incidental contributors. They neither comprise the whole program nor define it, but rather join with the other building blocks to deliver the desired outcomes. Other blocks include the skills and capabilities of cost professionals, predictive capabilities, implementing procedures, focused initiatives directed at specific cost issues and the many other activities and capabilities necessary for effective cost management.

IUSA management believes there is much to gain from this holistic approach and has embraced the process. Implementation is already underway.

Another key element we recommend is that, 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. We have discussed how an effective organization moves beyond numbers and reports to meaningful analysis and corrective action. Only people can make that translation of numbers to action, so people become the all-important, not-so-secret ingredient. We recommend that the cost professionals' role include the following:

- Direct support to work group management, helping and encouraging management to carry out their cost management responsibilities
- Preparation of analyses that directly lead to recommended corrective measures
- Assuring that the case for cost is heard in balancing priorities
- A focus on predictive methods and techniques, early identification of cost threats and elevation of cost issues while mitigation is still an option
- Development and implementation of supporting tools and processes.

The requisite skills need to be developed in the cost staff consistent with these new demands. Also, it is expected that the cost professionals will need to become more familiar with the details of the physical work. With time, such development efforts and integration of new skills will produce the staff of cost professionals required for the holistic approach.

We also recommend establishment of a cost support organization that:

- Is placed consistent with the priority of cost management
- Serves the cost management needs of all levels of management
- Develops a force of skilled cost professionals and assures those skills are continuously improved
- Has overall accountability for the development and implementation of the cost management program.

Organizational decisions by necessity must be carefully tailored to the particular traits of each company. We therefore avoid offering any prescriptive recommendations on how to structure an organization. We can offer our thoughts on what we have seen work best in the past, but a final design needs to be based on IUSA's circumstances, culture and people. Accordingly, the team in place to implement the holistic approach is best qualified to make that recommendation.

The most successful cost organizations we have seen feature a high reporting level, which immediately establishes the importance of cost and the credibility of the people. It is our understanding that IUSA has already made this decision and the placement of the cost organization will leave no doubt as to its standing as a corporate priority.

We have also seen success in using a matrix approach. A matrix approach is often dictated when a specialized skill is needed in a local organization but will be difficult to acquire, nurture and retain in that organization. This is indeed the case of the cost professionals we envision. They are needed at the local level, and should report to the local manager. They could have a "dotted line" relationship back to the central cost management organization, which would be their real "home." That organization would be responsible for their technical direction, supporting them with staff capabilities and providing training and career development.

The notion of a career path in cost management can be a valuable contributor to attracting and growing a strong cast of skilled cost professionals.

We also recommend training for managers, supervisors and cost support personnel in cost management techniques consistent with the holistic approach. Managers are rarely supported with training in cost management. They are left to their own devices with the result that some succeed and some do not, but all struggle unnecessarily. Training is especially important in the holistic approach since expectations for managers and support personnel are much greater than they are in traditional approaches.

Training is also essential to permit managers to make rational decisions on their information needs. For example, in developing the IUSA Line Worker Workforce Model, the needs of managers must be a critical input. However, in the absence of adequate training, we suspect that managers are not really able to effectively define such needs.

As a further and more detailed assist, we have provided an outline of various implementation tactics that one might consider as they implement the holistic approach (A Framework: Sample Cost Management Implementation Tactics; Appendix A). These are sample activities that may or may not be appropriate. They at least can serve as clarifying examples of the key components of a holistic approach. Our preference is to avoid any prescriptive "laundry list" of implementation tactics. Since the Company has already bought in to the concepts we have offered, we are confident they can do a good job of designing an implementation strategy that best meets their needs. Accordingly, we offer this list only as a sample of the kinds of tactics that might be considered. This framework is included in Appendix A.

Implementation Cost (NYSEG and RG&E shares):

During the strawman discussion process, IUSA has assessed the scope of implementing the recommended holistic cost management program and developed a preliminary estimate of the total costs for the Company (RG&E and NYSEG shares would be about 80 percent). Liberty has reviewed the scope, the bases, the assumptions, and pricing, and concurred the estimated costs are sound and reasonable. The major components of the implemented costs are summarized as follows:

(A)	ONE-TIME COSTS	COSTS ($ M)
	Initial Training Costs	
	Consultants - Development and Delivery	[redacted]
	RG&E and NYSEG - Staff Training	
	Analytics and Reporting Enhancement	
	Electric and Gas Operations - T&D	[redacted]
	Customer Services	
	Automation	
	Productivity Reporting - KPI & Dashboard	
	Total Costs - RG&E and NYSEG	3.9
(B)	**ANNUAL COSTS**	**COSTS ($ M)**
	Cost Professionals	[redacted]
	License Fees / Benchmarking Expenses	
	Total Costs - RG&E and NYSEG	1.2

The distribution of implementation costs for the first five years:

One-Time Costs (X 1,000)					
Year	**Labor**	**Outside**	**Lic Fees**	**Other**	**Total**
2012	-	232	-	340	572
2013	320	936	456	40	1,752
2014	488	483	565	-	1,536
Total	808	1,651	1,021	380	3,860

Annual Costs (X 1,000)					
Year	**Labor**	**Outside**	**Lic Fees**	**Other**	**Total**
2012	$ 952	$ -	$ 172	$ 31	$ 1,155
2013	$ 952	$ -	$ 172	$ 31	$ 1,155
2014	$ 952	$ -	$ 172	$ 31	$ 1,155

Benefits

Liberty is very confident that the holistic cost management program, if implemented as promised by the Company, will translate into substantial savings for customers. Specifically, these savings will help the Company meet its cost reduction obligations and will also allow more necessary work to be completed without proportionate increases in spending.

It is not possible to precisely quantify such benefits. Nevertheless, we believe the tangible results will be substantial; in the many millions of dollars, and perhaps much more. In fact, we have seen the holistic approach implemented twice and the savings have been cited as in the tens of millions of dollars for a $400 million construction project and over $150 million for an electric and gas utility (Con Ed). Executives at both those companies embraced the program, despite its implementation costs, and were richly rewarded for their confidence.

B. Work Planning

1. Background

Effective operation starts with good planning. Work Planning should operate under a comprehensive and systematic approach to coordinate the accomplishment of work that needs to be done. We examined IUSA's principal work management processes and supporting functions, such as assembling of work packages, work breakdown structure, estimating, material management, technical support, and fleet management. We also examined whether this process is consistent with budgeting processes and effectively linked to the management of projects and programs.

The criteria by which Liberty evaluated work planning included the following:

- Work packages for physical workers should be designed to clearly communicate the key elements of the work and allow employees to optimally complete the work.
- Work crews should have timely access to good technical support.
- A Material Management Program should be in place that is integrated with the work planning process and assures timely availability of necessary components.
- Equipment and vehicles should be ample in quantity and their design should be consistent with efficient completion of the intended work.
- A clearly defined work breakdown structure (WBS) should be in place that parses the work in logical categories consistent with the mangers' needs.
- A credible estimating process should be in place with standard work tasks, procedures, unit rates, estimating guidelines and capable estimators.
- The work management process, encompassing all of the above criteria, should link seamlessly with established projects and program management systems.
- The work management process should be consistent with the Company's budgeting system and link to that system where appropriate.

2. Findings

a. Work Management Processes and Packages

i. Work Management Tools

The Work Management System Module in the SAP system serves as IUSA's main tool; it has a procedural diagram on most of the field operations. However, they are all financially-focused, and involve some 20 to 50 steps.

The key components of the work management system include:

- Compatible Unit (CU) Designs (including Cost Simulation)
- CU Orders (including Multi-Operation Update)
- Equipment Auto Creation (at Release and Post Release)
- Functional Location Auto Creation (Intelligent Design Points)
- Shop Papers (Notification and Order Related)
- Joint Use and Joint Ownership (including Joint Billing)
- Settlement Rules and Error Checking

- CU Order Work Flows
- Construction Measures (including Auto Creation)
- Compatible Unit Administration
- SD Billing (Order and Non-Order Related)
- Fleet Orders and Non-CU Orders
- Labor Reporting and Settlements.

The key integration points for work management include:
- CU Order with Estimated Cost Billing
- CU Order with Actual Cost Billing
- Non-CU Orders
- Miscellaneous Billing (with and without CU Orders)
- Fleet Orders
- Interfaces (WMS – Power Plan, GIS, Avenue, Fleet Odometers)
- Interfaces (SD Remittance, Credit Agency)
- Master Data Administration
- SD Customer Dunning
- CCS Integration Points (Street Lights)
- Materials Management Integration Points
- Labor Reporting Integration Points
- Accounting Integration Points and Power Plan Interfaces.

Major IUSA projects require multiple work orders due to financial requirement to separate work orders by township and due to SAP's inability to accommodate projects of larger size (information exceeding 500 lines). We conducted a field visit to a capital project being performed by the Mobile Work Force; it included eight work orders. As the distribution line involved crosses one street and moves into a different township, field workers have to charge their time to a different work order. The requirement is to comply with the need to maintain property tax records and is required due to SAP master data configuration. Such requirements introduce unnecessary inconveniences in field operations, without producing any efficiency or effectiveness.

ii. Work Management Processes

Work flows differ according to the types of work involved. In general, we found them effective, in that jobs are getting completed. The major Electrical Operations work functions, including Transmission, Distribution and Substation, all operate under an SAP work process diagram depicting the normal work flow and interfaces.

The next table shows the SAP work process diagrams available for transmission and distribution work.

Diagram No.	Flow Diagram Description
EC-01	Electric Distribution Construction with Charges
EC-02	Electric Distribution Construction without Charges
EC-03	Electric Distribution Construction Simple Services
EC-04	Electric Distribution Construction Relocation or 3 Phase Upgrade

EC-05	Electric Distribution Construction Single Phase Upgrade Same Location
EC-06	Electric Transmission Construction with Charges
EC-07	Electric Transmission Construction without Charges
EC-08	Electric Distribution Construction Street – Area Lights – Install/Remove
EC-09	Electric Private Line Construction
EG-01	Electric General Maintenance
EG-02	Electric General Maintenance Attachments
EG-03	Electric Private Line Purchase or Conveyance
EP-02	Electric Planned Maintenance
EU-01	Electric Distribution Corrective Maintenance Damage Billing
EU-02	Electric Distribution Corrective Maintenance Street Area Light Repair
EU-03	Electric Corrective Tree Trimming
EU-04	Electric Corrective Maintenance

The following SAP work process diagrams are available for substation work.

Diagram No.	Flow Diagram Description
SC-01	Substation Construction With Charges
SC-02	Substation Construction Without Charges
SG-02	Substation General Settings Maintenance
SU-01	Substation Corrective Maintenance
SP-02	Substation Planned Maintenance

For Gas Operations work, the following SAP work process diagrams exist.

Diagram No.	Flow Diagram Description
GC-01	Gas Construction With Charges
GC-02	Gas Service Relocation Construction With Charges
GC-03	Gas Construction Without Charges
GC-04	Gas Construction With Charges – Replacement
GC-05	Gas Construction Without Charges – Replacement and Reliability
GC-06	Gas Transmission Construction With Charges
GC-07	Gas Transmission Construction Without Charges
GP-02	Gas Planned Maintenance
GU-01	Gas Corrective Maintenance
GU-02	Gas Corrective Maintenance – Leak Repair and Backlog
GU-03	Gas Corrective Maintenance – Damage Billing

All these SAP flow diagrams place emphasis on interfacing with SAP, involving from 20 to 50 steps, which makes them too complex to display here.

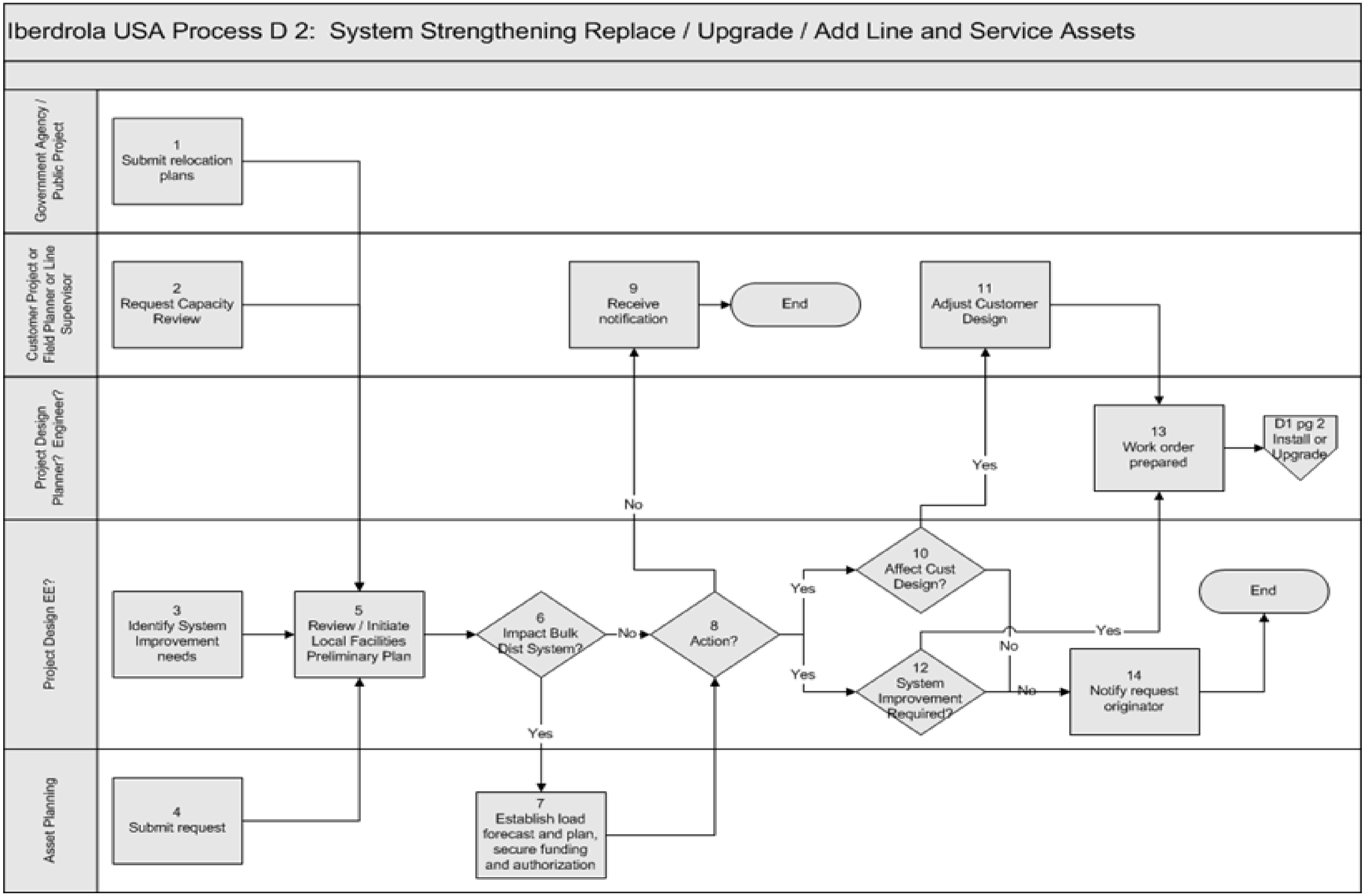
iii. Field Work Flow Diagrams

Electric Operations has field work flow diagrams for the following four major processes:

D1. Connections, Installation of New or Upgraded Service Facilities
D2. System Strengthening Replace/Upgrade/Add Line and Service Assets
D3. Maintain Line and Service Assets: Maintenance and Mitigation

D4. Restore Service or Repair Trouble.

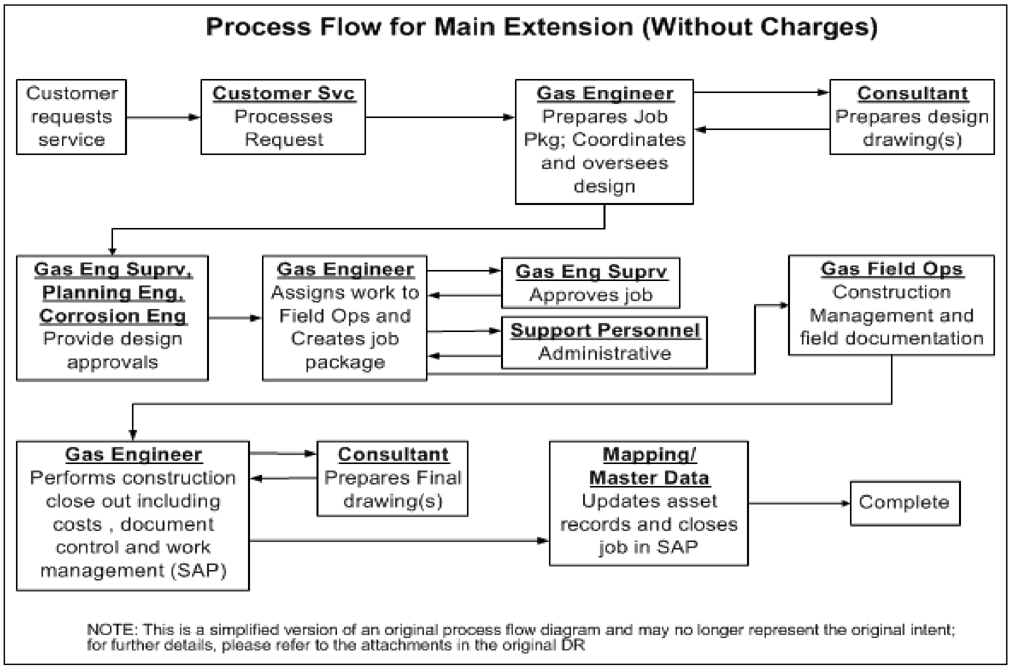
For illustration purposes, the D2 work flow diagram is shown below:


Iberdrola USA Process D 2: System Strengthening Replace / Upgrade / Add Line and Service Assets
Government Agency / Public Project
Customer Project or Field Planner or Line Supervisor
Project Design Planner? Engineer?
Project Design EE?
Asset Planning
1 Submit relocation plans
2 Request Capacity Review
3 Identify System Improvement needs
4 Submit request
5 Review / Initiate Local Facilities Preliminary Plan
6 Impact Bulk Dist System?
7 Establish load forecast and plan, secure funding and authorization
8 Action?
9 Receive notification
End
10 Affect Cust Design?
11 Adjust Customer Design
12 System Improvement Required?
13 Work order prepared
14 Notify request originator
D1 pg 2 Install or Upgrade
Yes
No

Gas Operations has work flow diagrams on the following two major processes:

D1. Process Flow for Main Extension (Without Charges)
D2. Process Flow for Basic Gas Service (Without Charges)

For illustration purpose, a simplified version of the Main Extension flow diagram is shown below.



iv. Work Packages

Engineering-generated work packages by designers/planners are comprehensive and complete. The sequence shown below identifies how an RG&E Electric Operations engineer plans a Troubled Circuit job:

- Troubled circuits are identified and notifications will generally come through the Energy Control Center
- Distribution Engineer field checks to scope the problem and identify a proposed solution
- When design is completed, a cost estimate will be performed based on the engineer’s experience, pricing books and knowledge (there are no established estimating methods or credible historical unit rates)
- The drawings are redrawn
- Specialty work such as manholes and duct installation will be contracted
- Procurement will invite pre-certified vendors and contractors to bid on job
- Real-time reverse auction bids will be conducted
- Once a contract is awarded, procurement will notify engineer to initiate purchase orders
- Engineer is essentially the project manager
- Engineer will prepare material PICK list, secure necessary permits, assemble electric subway maps and generate work order in SAP for construction to perform work.

Field generated work packages by field planners are also comprehensive and inclusive. The next list illustrates how Gas Operations in the field plans and completes a Gas Leak Repair job

- Work is assigned via the Work Center inside SAP
- Customer services or engineering enters work orders into SAP
- Field Planner checks for new leak work orders in the system to pre-plan workload
- When work orders are released, field planner coordinates the acquisition of needed information; *e.g.*, gas main maps, electric subway maps, past service order history
- If public work, field planner will secure permits
- Field Planner goes on line to secure legal stake-out tickets (by township and affected utilities) from Underground Facility Protection Organization (UFPO – 811 Dig Safe)
- Field Planner releases courtesy letters to notify affected property owners
- The work is then released to be performed in the field
- Leader of crews performing the work will sign off work orders as completed
- Supervisor will sign if it is a Type I leak
- QA/QC will perform spot check.
- Crews fill out Leak Work Order Report and return to field planning for filing.
- Field Planner updated in SAP as job completed.

Planned or estimated job-hours are not made available in any work packages; *i.e.*, there is no clear productivity expectation or measurement basis. We observed little focus or emphasis on meeting cost constraints.

b. Technical Support

The technical support is timely and good in emergency situations for both Electrical and Gas Operations.

The designers and engineers are conscientious about providing full and timely support to the work force in the field. They solicit input from the field planners and supervisors in the initial walkdown of the design. They also provide around-the-clock coverage during physical work in the field. Discussions with planners and supervisors during interviews and field visitations indicated that the technical support had been adequate and seldom resulted in down time. One supervisor did express concern that future support might be affected, if the low staffing in engineering (due to attrition, termination, retirement or on-loan to other divisions) continues.

c. Material Management Program

i. Procurement Process

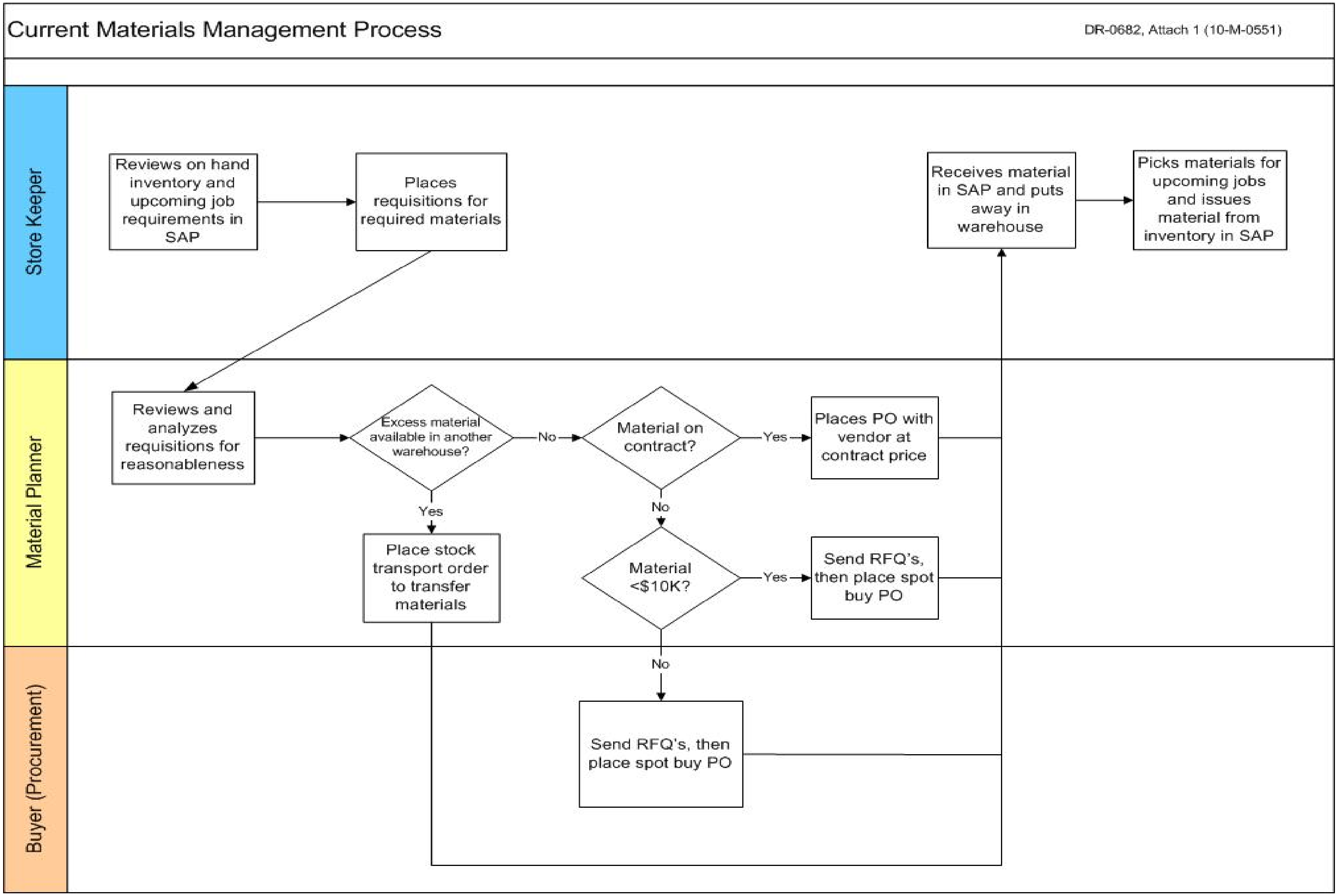
The procurement process is comprehensive and sound. A Procurement Service Policy Manual covers policies and procedures on purchasing, the sealed-bid process, the competitive-bid process, the single/sole source purchase justification, supplier qualification, bid evaluation, purchase order preparation and contract administration.

ISA has developed global Iberdrola Group Procurement Rules to establish the principles governing the centralized procurement system for better utilization of resources and management control in the acquisition of equipment, materials, and services. Different procedures apply to distinct types of acquisition; *e.g.*, centrally-managed, coordinated, recurring, direct, and urgent purchases or the contracting of advisory consulting services.

ii. Material Management Process

IUSA's general policy is to procure materials, equipment, and services competitively, recognizing where circumstances may make competitive methods impractical. In such cases, a single/sole source purchase can be considered if appropriately justified. Examples include new technology, unique design, or requiring special skills.

A simple flow diagram on the Material Management Process follows:


Current Materials Management Process
DR-0682, Attach 1 (10-M-0551)
Store Keeper
Material Planner
Buyer (Procurement)
Reviews on hand inventory and upcoming job requirements in SAP
Places requisitions for required materials
Receives material in SAP and puts away in warehouse
Picks materials for upcoming jobs and issues material from inventory in SAP
Reviews and analyzes requisitions for reasonableness
Excess material available in another warehouse?
No
Yes
Place stock transport order to transfer materials
Material on contract?
Yes
Places PO with vendor at contract price
No
Material <$10K?
Yes
Send RFQ's, then place spot buy PO
No
Send RFQ's, then place spot buy PO

iii. Bid Evaluations

The bid evaluation process is extensive and thorough:

- System or Design Engineering assembles the appropriate approved material technical specifications
- Approved requisitions then go to Procurement Services for bid and purchases
- Returned bids are evaluated by engineering for compliance with the specifications
- Procurement compares the commercial and pricing aspects of submitted bids for materials, equipment or services and to ensure that all bid proposals are considered based on their commercial merit
- The purchase order is awarded to the qualified supplier offering best value and meeting technical and commercial requirements
- The selection may be based on an evaluated price or consideration of qualitative factors to determine best value
- For stock items, the Material Planner will work in collaboration with Supply Chain to bid the required materials based on existing Outline Agreements.

iv. Stocking and Inventory Management

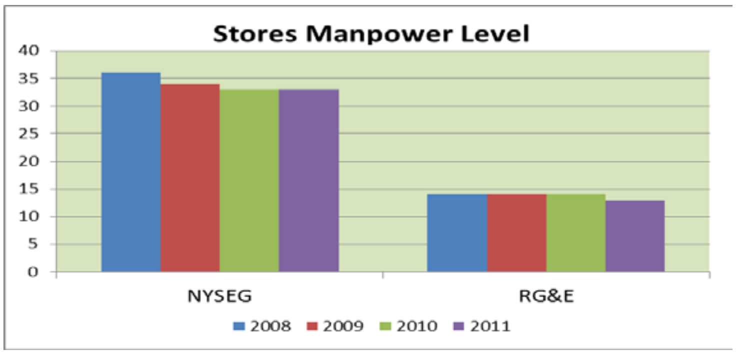
Materials for stock are requisitioned by the Division Operations Storekeeper based on historical inventory level. Material for minor projects is requisitioned based on material requirements detailed in the Work Order. The Stock Requisition is routed to the Material Planner, who then creates Purchase Orders which follow the established approval process. Bulk materials in inventory are issued via the PICK list and charged to the jobs.

RG&E charges routine inventory management expenses directly. NYSEG uses a distributed factor for Stores Overheads (*e.g.*, about 19 percent in 2010). This factor seeks to allocate the costs of purchasing, freight, and stock handling relating to the storage of materials to all material issues on a monthly basis. Industry information available to Liberty would place this level is at the high end of the industry range of 15 - 20 percent.

Overall performance for Stores Management has been good; the two key measurements of Critical Item Availability and Inventory Accuracy exceeded 99 percent.

IUSA's Inventory Turnover Ratio of 3.29 in 2010 is in line with the industry average of 3.0 that Liberty has observed.

The Business Transformation Group has identified and implemented the standard SAP functionality for Materials Requirements Planning (MRP) to improve warehouse efficiency by automating the material planning and replenishment processes. This initiative has not resulted in any significant impact on Stores manpower. The reduction in RG&E is due to one individual's taking medical leave. The reduction in NYSEG is due to individuals' taking retirement.



v. Approval of Standard Materials

Procurement of inventory material is only fulfilled with standards-approved specifications or following standards-engineering approval for a new material manufacturer that meets the approved standard.

vi. Delivery Process

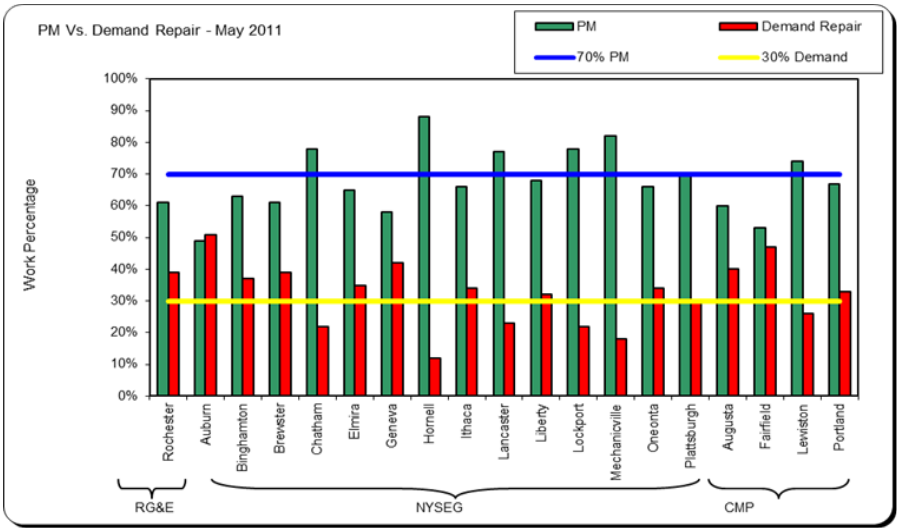
Stocking materials are generally picked up by work crews. Arrangements are made with vendors to deliver oversized items, such as distribution poles, to the work location.

d. Fleet Management

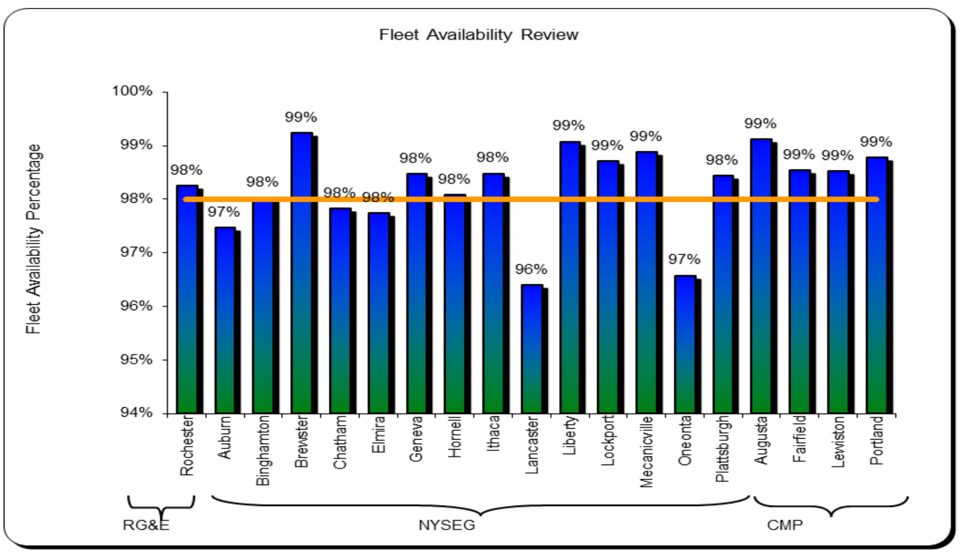
i. Transportation Department

The Transportation Department manages the Company's fleet; we found it to be an effective and efficient organization. It operates under sound principles and comprehensive sets of procedures that cover the basic operations (acquisition, preventive maintenance, productivity monitoring, reporting, analysis, auditing, auctioning, environmental stewardship, legal compliance, fuel hedging, and continuous improvement).

The Transportation Department has a sound Fleet Staffing Analysis Model for determining the right resource level to meet demand requirements. The current balance is 70 percent preventive maintenance and 30 percent demand repair.



Fleet Availability Reports are generated to measure garage performance. Most of the garages achieved a high standard of 98 percent.

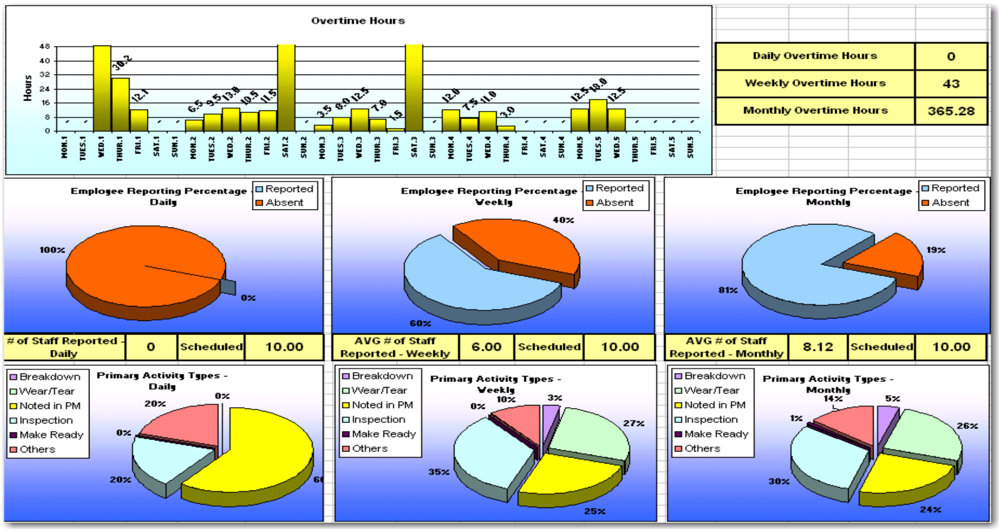


Utilization Reports identify where business areas may be under-using or over-possessing vehicles and equipment types. Standard hourly rates address the different types of vehicles and equipment.

The Department used to employ M4, which comprises an effective fleet management tool. The change to SAP (primarily a financial information driven system), has, however caused the loss of important functionalities of fleet management. A detailed comparison has been made to contrast the deficiencies of SAP in great details in a number of areas. They include general requirements, equipment inventory tracking, shop operations, equipment costs-history data, labor analysis, parts inventory control, fuel inventory control, ad hoc query-report generator, management reporting tools, audit trail, user-defined tables, and vendor support program.

ii. Performance & Analysis

The Transportation Department has good effective tools to monitor productivity. The design of a dashboard to monitor and forecast the performance of mechanics is of high quality. The results are routinely reviewed with the supervisors, who in turn will review with staff technicians.

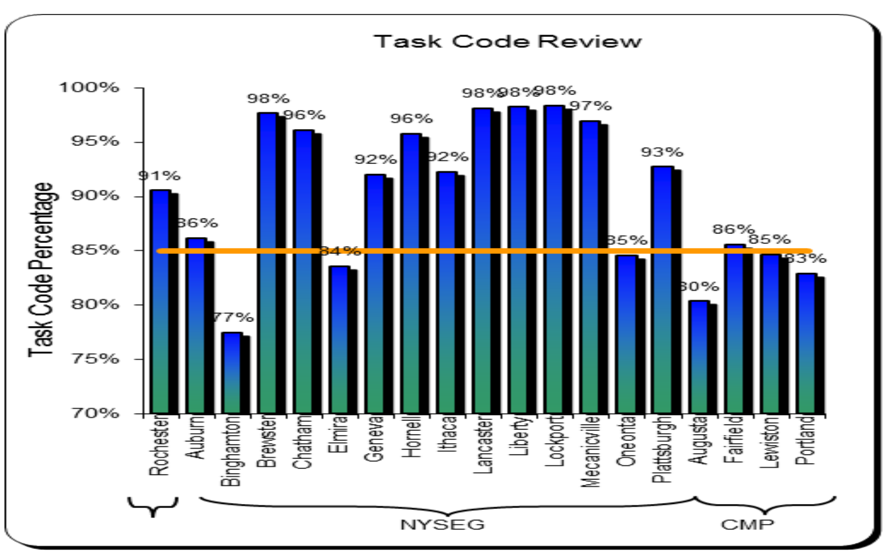


The only shortcoming of this performance dashboard is, similar to metrics and reports generally at IUSA, we found no explanations or analysis of the results shown by performance indicators.

An IUSA improvement initiative has resulted in elimination of 90 fleet units, with a projected cost savings of $400K. A second wave is being implemented to remove at least 100 units, with a projected cost savings of $1 to $3 million.

iii. Internal Benchmarking

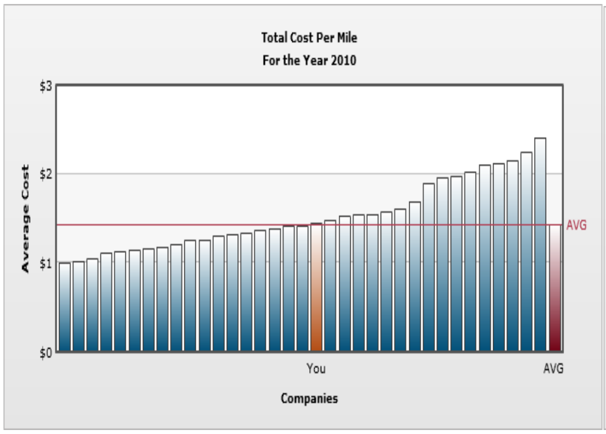
Productivity of mechanics are monitored by task code unit job-hour rates

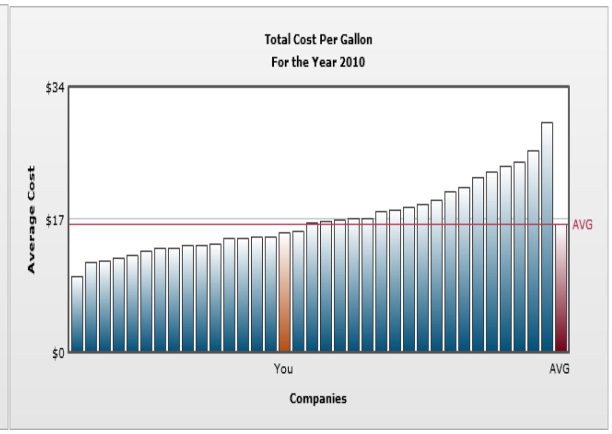


Lessons learned are frequently shared among supervisors in meetings on a regular basis, but the effort and the resulting cost savings are not documented.

iv. External Benchmarking

The Company participates regularly with a fleet benchmarking company. IUSA compares favorably with the industry in terms of cost per mile and cost per gallon. IUSA possesses a younger fleet, which helps explain this difference.





e. Work Breakdown Structure

SAP applies a Work Breakdown Structure (WBS) for capturing and reporting costs related to Projects. Projects are categorized by the project type field, which designates the projects as Electric, Gas, Common, or Production.

The next table summarizes the Electric Capital Work Breakdown Structure.

Work Function	Level 1	Level 2
Production Hydro	Production Hydro - Planning Level	Production Hydro
Transmission Lines	Transmission - Planning Level	Transmission New - OH
		Transmission New - UG
		Transmission Replace/Upgrade - OH
		Transmission Replace/Upgrade - UG
		Transmission – Land
Distribution Lines	Distribution - Planning Level	Distribution - Increased Capacity - OH
		Distribution - Increased Capacity - UG
		Distribution - Replacement - OH
		Distribution - Replacement - UG
		Distribution - Joint Use - Distribution
		Distribution - Land
		Distribution - Network - UG
		Distribution - Other Line Devices
Customer-Industrial / Commercial	Customer - Planning Level	Customer - Industrial / Commercial - OH
		Customer - Industrial / Commercial - UG
Government Highway/Road Jobs	Government Highway - Planning Level	Government Highway / Road Jobs OH
		Government Highway / Road Jobs UG

Residential Line Extensions	Residential Line Extensions - Planning Level	Residential Line Extensions - OH
		Residential Line Extensions - UG
Service Connects	Service Connects - Planning	Service Connects -New - OH
		Service Connects -New - UG
Street Lighting	Street Lighting - Planning	Street Lighting
Storm Restoration	Storm Restoration - Planning	Storm Restoration - Transmission Lines
		Storm Restoration - Distribution Lines
Substations	Substation - Planning Level	Substations - New - Transmission
		Substations - New - Distribution
		Substations Replace/Upgrade - Transmission
		Substations Replace/Upgrade - Distribution
		Substations - Land
Distribution Line Transformers	Distribution Line Transformers - Planning Level	Distribution Line Transformers
Electric Regulators /Reclosers	Electric Regulators/Reclosers - Planning Level	Electric Regulators
		Electric Reclosers
Electric Meters	Elec Meters - Planning Level	Electric Meters
Misc – Electric	Misc Electric-Planning Level	Miscellaneous Electric

Electric Operations costs are collected at either the WBS or Work Order (CU or PMO) level, depending on the project type. Electric T&D Line and Substation (with the exception of pre-cap items) costs are captured at the Work Order level (CU or Non-CU Order), which is tied to a Project/Planning level WBS. Electric Production, General Property (Land, Buildings, and Equipment, for example) and Pre-Cap purchases are collected on a charge level WBS.

Gas Operations routine O&M “physical” work is captured through a series of established Internal Orders (IO) and Preventative Maintenance Orders (PMO). Specialty work can also be posted to a work order (WO) or directly to a Work Breakdown Structure (WBS) number.

Work Breakdown Structure			
Operations	Company	Structure	No. of accounts
Electric	NYSEG	WBS Elements	195
	RG&E	WBS Elements	152
Gas	NYSEG	Internal Orders	417
		Preventive Maintenance Orders	554
		WBS Elements	50
	RG&E	Internal Orders	50
		Preventive Maintenance Orders	95
		WBS Elements - None	0

The Work Breakdown Structure is designed and determined by the Financial Department. Cost tracking numbers and work orders are generated to keep track of costs for specific purposes, as required.

f. Cost Estimating Processes

i. Electric Operations

The cost estimation process for electrical distribution projects consists of the creation of Compatible Unit (CU) work orders in SAP. The SAP work management system is used for estimating electric distribution projects. Estimating of electric transmission and substation projects is done utilizing separate in house computer applications, with the flexibility to account for the unique nature of these larger type projects. The transmission estimating application is Excel based. The substation estimating application is ACCESS based.

Scheduling of mandated or required work for non-measurable items uses the prior year's inspection and survey cycles or compliance dates from remedial compliance work. The estimating method uses historical times to complete, the supervisor's past experience, and knowledge of work productivity.

The field generally does not review prepared estimates. IUSA has no requirement to reconcile final costs that substantially overrun the original authorized project estimate. Cost effective organizations use such a process to identify and address causes of cost growth.

IUSA is currently developing an Electric Capital Delivery Project Management Procedures Manual. A chapter on Cost Management will include sections addressing Cost Estimating, Cost Budgeting and Cost Control. The scope of this documentation effort includes only major projects. Cost estimation of other physical activities in Electric Operations will still have to be addressed elsewhere.

ii. Gas Operations

The cost estimating process is different for different types of work. For Gas Engineering designed projects, SAP generates cost estimates, using CU as building blocks.

Routine RG&E work estimates use an ACCESS Database, which applies actual Pay Identifier (PID) rates from each gas contractor. SAP will also be used for smaller, gas-main jobs and individual-service work. Estimates for NYSEG routine work performed by contractors are developed based on the PID. The format of the cost estimate varies by division.

For non-measurable work items, all mandated or required work is scheduled and completed based on the prior year's inspection and survey cycles or based on compliance dates from remedial compliance work. The estimating method used is based on the historical times to complete, the supervisor's past experience, and knowledge of work productivity.

There generally is no review of estimates by the field.

iii. Cost Estimating Tools

SAP offers the main cost estimating tool, using Compatible Units (CU) to build cost estimates for both Electric and Gas Operations work orders. The tool has limited ability to adapt to other categories of work in the field.

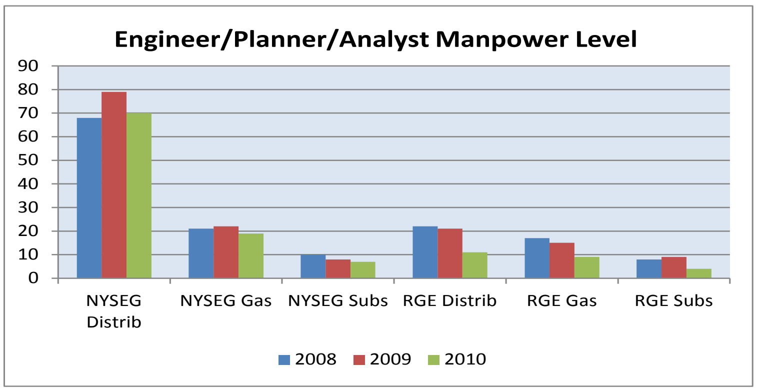
Even for major projects, most designers and engineers supplemented the SAP cost estimates with their own spreadsheets to arrive at the project cost estimates. The Compatible Unit has not been maintained. Users have to select the data with caution; they often choose to override the standard rates. For other types of work, most engineers or planners use tools developed on their own to perform cost estimates.

For Gas Operations, RG&E developed its own standard unit cost on ACCESS for repetitive measurable work, using actual PID rates from each gas contractor. NYSEG is in the process of developing the same ACCESS database for repetitive, measurable work.

Electric Operations uses the Compatible Unit as the standard for costs on repetitive measurable work. Neither Gas Operations nor Electric Operations presently has any approved unit job-hour rates for any type of repetitive work.

iv. Cost Estimators

IUSA has no dedicated, professional cost estimators. Design engineers at RG&E or planners at NYSEG prepare all estimates. A significant decrease in engineering and planning resources jeopardizes timely production and quality of the cost estimates. The next table shows that staffing in areas that may include estimate preparation have trended downward.



A contracted engineering firm does have full-time cost estimators who develop project cost estimates.

g. Project Management Processes

Both Electric Engineering and Gas Engineering oversee the project management aspects of construction projects; *e.g.*, such as planning, design, engineering, and close out. When a project reaches the construction phase, it is released to Field Operations, which performs the construction management function.

Construction Management by Field Operations may include scheduling the work to meet the project management schedule, identifying internal or external resources, requesting procurement materials, overseeing construction, and performing inspection activities. Upon completion of the construction phase, the work package returns to Engineering for close out activities.

The work management process supports the overall project management process. Report Chapters XI and XII address project management.

h. Work Management Process/Budget Consistency

The Annual O&M Budgets of Transmission & Distribution, Substation, and Gas Operations are developed based on the anticipated workload for the upcoming year. These budgets include Field

Work Plans for mandated work, emergency response needs, and a percentage of internalized capital construction work. The Field Work Plans, inspection, and maintenance of electric assets have generally been consistent from year to year. Planning for the variable components in the O&M budget, such as emergency response and internalized capital, relies upon historical information and upcoming planned work.

IUSA does not develop its budgets on a bottoms-up basis. The volume of work to be accomplished is planned at the macro level. Other key criteria, such as unit job-hour rates, crew wage rates, unit cost and other factors are generally not considered during the budgeting process. The top-down budget derives from past expenditure levels for various categories of work.

The business units plan and manage their work in accordance with the approved budget. All use the budget as the only baseline to monitor costs. All cost reporting tools are designed to align with the budgets. Monthly cost variance reports are generated to monitor the actual costs against both the capital and O&M Budgets.

3. Conclusions

7. The work management processes for all physical work are pertinent, logical, and comprehensive.

IUSA work planning processes consider the essential details. The planners are experienced and possess good judgment. The work packages delivered contain essential information to complete the required tasks.

8. The current work management system module in SAP is essentially a work dispatching and work planning tool, not a complete system that is dynamic enough to manage real-time progress, productivity, and costs.

This gap can be addressed by implementation of the holistic cost management system. The development of work management capability should focus on: (a) workforce performance, (b) effective performance measure, (c) analysis, (d) corrective actions (Refer to Cost Management Framework Sections C-4, C-5, C-9 and C-10 in Appendix A). The existing Work Management System module is adequate in dispatching major projects and routine tasks. Once the work orders get initiated, the work will get completed in the field. However, the system is incapable of managing progress, productivity, and costs. In the past, there were no requirements to monitor productivity and costs. When the holistic cost management program is implemented, SAP will be upgraded to include the necessary features.

9. The lack of planned or estimated job-hours in work packages reflects a lack of productivity emphasis and specific expectations. *(Recommendation #2)*

The work packages do not communicate the planned job-hour expectation to the field. Only the job cost information is available. Without clear expectations, performance accountability is lessened. Without monitoring, there is degradation in awareness of how productivity is trending.

10. Technical support during field work is responsive for emergency work and adequate for routine work.

On emergency situations, engineering provides timely and effective solutions such that there is no progress impact in the field. For routine work, the designers and engineers are committed to provide complete technical information before releasing the work to the field. Based on the feedbacks acquired from the supervisors in our field visitations, the technical support has been adequate.

11. The material requisition system is effective in securing competitive pricing; the delivery of required components is well planned and expedient; the warehousing system is efficient.

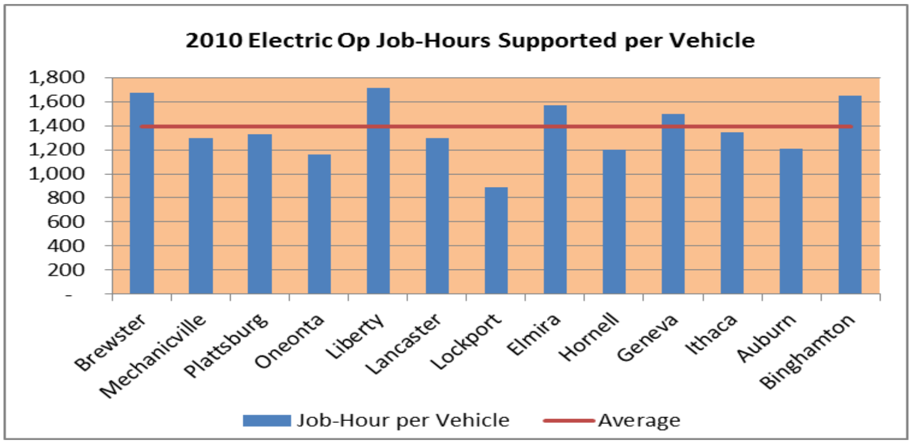
The procurement process is rigorous and covers the essential elements. It ensures qualified suppliers to provide best pricing via competitive bidding. It uses several types of unit pricing contracts to secure best values. The warehouse examined is well organized and stocked for regular materials. Arrangements to deliver heavy equipment to jobsites are well planned. Discussions in interviews and field examinations indicate that downtime due to material unavailability is kept to a minimum.

12. The Transportation Department that manages IUSA's fleet is an effective and efficient operation; it uses a sound fleet staff analysis model in determining the right resource level to meet demand requirements.

The Transportation Department has effective guiding principles and comprehensive sets of procedures that cover all the basic operations. Performance of mechanics is effectively managed. Utilization Reports are generated to indicate if business lines under-utilize or over-possess any vehicles and equipment. Standard hourly rates are developed for different types of vehicles and equipment. As a result, IUSA compares favorably to the industry average, as demonstrated by its external benchmarking effort.

The amount of work in a region should drive fleet size. One key performance indicator that the Transportation Department can add to its comprehensive set of performance metrics is how much the vehicles are utilized to support physical work. A relationship can be developed to measure the field operation (capital and O&M) in job-hours per vehicle. Keeping a good history on this indicator by business area will provide a true measure if the fleet size is optimal. This is especially important when the resource levels fluctuate over time with ever-changing workload demand.

The following indicator is developed for Electric Operations by region for illustration:



Such indicators can only to point to areas of interest. They do not support conclusions without further analysis. Regions below the average line indicate that their fleets are supporting less direct work as compared with other regions. The Lockport region has a small fleet, and might merit special considerations. The other three outliers, Oneonta, Hornell, and Auburn, should be evaluated to understand the reasons they compare unfavorably to other regions.

Regions above the average line have fleets that are supporting comparatively more direct work. The four regions, Brewster, Liberty, Elmira and Binghamton, should be evaluated to see if they need to increase their fleet size. Other factors to be considered in this evaluation include vehicle rental costs, vehicles loaned from other regions, more second shift work, for example.

Over time, IUSA can accumulate enough historical data to arrive at an optimal fleet size level. Similar indicators can be developed for Gas Operations.

This illustration is to demonstrate the kind of new performance metric and cost analysis that could be developed under the holistic cost management program.

13. Mechanics at the garages are effective in maintaining vehicles and equipment; work crews are able to mobilize readily to work locations in a reasonably expeditious manner.

Fleet Availability Reports are generated to measure garage performance. The Transportation Department has a sound Fleet Staffing Analysis Model in determining the right resource level to meet demand requirements. Our observations and discussions with planners and supervisors in the field visitations demonstrated that work crews are able to get to the work locations despite the recent elimination of spare vehicles.

14. The current Work Breakdown Structure provides adequate and essential details for the managers and supervisors to complete physical work.

The Work Breakdown Structure is established originally more for major capital work. It has been expanded to include other types of activities. Work orders can be generated to track expenses, as required. As additional productivity measurement requirements arise, the current structure can be enhanced to provide essential details for the managers and supervisors to monitor productivity of the physical work force.

15. Cost estimating capability in IUSA is a major weakness; the cost estimating process is not uniformly established and approaches to estimating various types of work need to be standardized; there are also no full-time internal professional cost estimators. *(Recommendation #3)*

Credible cost estimates establish crucial cost control baselines. Cost estimates are used for project commitment, budgeting, funding authorization, cost/risk assessment, bid-evaluation and cost forecast. There are no internal full-time cost estimators, although the engineering firms see the importance of employing professional cost estimators. The engineers are provided the following standard tools to develop cost estimates: SAP for electric and gas distribution, MS Access for electric substation and protection, and MS Excel for or SAP CU for transmission. However, because of the lack of a standard cost estimating process, not all engineers are developing cost estimates in a fully consistent manner. One major shortcoming identified is the lack of documenting project scope definitions, bases and assumptions, which all can affect significantly the final costs. Also, there is no requirement to reconcile the project final costs that overrun the original authorized project estimate substantially to understand project cost growth.

16. The integrity of the installation-rate databases is a concern; SAP uses the Compatible Unit (CU) to build estimated cost for every work order, but it has not been adequately maintained. *(Recommendation #3)*

The Compatible Unit is not being adequately maintained due to the engineering resource shortage. Users often have to override the standard rates based on personal judgment. The lack of consistency in estimate development does not allow these cost estimates to be used as credible cost control bases.

17. The same work management processes are used in a project environment in a consistent manner.

The same work management processes are used in a project environment. Engineering oversees the project management aspects of construction projects including planning, design, engineering and close out. Once the project reaches the construction phase, the job is released to Field Operations which fulfills the construction management function. Electric Operations in NYSEG could assign the major project to Mobile Work Force. Supervisors of Gas Operations will take on the projects if their crews are available and have the required skills.

18. The work management system is consistent with the Company budgeting system.

Work plans are managed within the budget constraints. All business units use the budget as the only baseline to monitor their costs. Low priority work gets delayed if funding is not available or when the budgets start to overrun.

4. Recommendations

2. Begin monitoring Actual Job-hour expenditures versus Planned Job-hours for Electric and Gas Operations; provide "Planned Job-hours" for all work packages issued to the field. *(Conclusion #9)*

By requiring future work packages to include Planned Job-hours, which are readily available in some areas of work, there should be cost savings because productivity normally will improve when monitored. The magnitude of cost savings cannot be determined until the end of the year, depending on how much improvement is made.

To gauge the magnitude of cost savings that can be attained, we performed an estimate on the savings based on three different scenarios to demonstrate the potential cost savings that can result from 1, 3 and 5 percent productivity improvements.

Using the total actual job-hours of 2010 as a base and assuming at least 70percent of the work is planned in O&M work, we calculated the potential O&M cost savings to be about $0.45 million (at 1 percent), $1.35 million (at 3 percent), and $2.25 million at five percent). See Tables 1, 2 and 3 below.

We similarly calculated the magnitude of cost savings for Capital work. Because most of the capital work is contracted, the projected cost savings is not substantial. However, it is still a good practice to be consistent and monitor the capital work the same way as the O&M work. Capital work is normally 100 percent planned. We calculated the potential Capital cost savings to be about $22K (at one percent), $65K (at three percent), and $109K (at five percent. See Tables 1, 2 and 3 below.

This estimation of benefits uses assumptions in the uncertain areas. Actual outcomes will depend on multiple factors, such as effective work planning, credible planned job-hours, and effective job execution, among others. The current mode of operation in IUSA is to "get the work done," without focusing sufficiently on what the amount of effort should be. Improvement will come from changing the philosophy and attitude that every job should proceed under reasonably clear expectations, and that it is essential to meet that expectation on a job-to-job basis. By adopting this new attitude, the new mode of operation is to meet the performance target on every job. All workers will be motivated to find ways to be more efficient on a day-to-day basis. By comparing the Actual Job-hours to Planned Job-hours on a monthly basis, cost analysis will have to be performed on significant variances and the problem areas will get identified for corrective actions. When the process is done correctly, favorable results will follow. This monthly cost analysis of comparing Actual to Planned Job-hours will be performed under the holistic cost management program.

Table 1 - Cost Savings from 1% Productivity Improvement
Back-up to CBA 5.1
Monitoring Field Job-Hour Expenditures by Including Planned Job-Hours in Work Packages

Assumptions on Percent of Work Planned: 100% Capital, 70% O&M

Resource	Description	Operations	OpCo	Capital	O&M	Remarks
Internal	(A) Total 2010 Actual Job-Hours	Electric Op	NYSEG	12,853	535,237	DRs # 934 & 936
			RG&E	15,122	153,461	DRs # 935 & 937
		Gas Op	NYSEG	8,695	237,240	DRs #954 & 956
			RG&E	676	179,288	DRs #955 & 957
	(B) Percent of work Planned	Electric Op	NYSEG	12,853	374,666	100% Cap; 70% O&M
			RG&E	15,122	107,423	100% Cap; 70% O&M
		Gas Op	NYSEG	8,695	166,068	100% Cap; 70% O&M
			RG&E	676	125,502	100% Cap; 70% O&M
	(C) Projected Job-Hour Savings (1% Improvement)	Electric Op	NYSEG	129	3,747	1% on Planned Work
			RG&E	151	1,074	1% on Planned Work
		Gas Op	NYSEG	87	1,661	1% on Planned Work
			RG&E	7	1,255	1% on Planned Work
	(D) Wage Rates (WR)	Electric Op	NYSEG	[redacted]		See Calc Below
			RG&E			See Calc Below
		Gas Op	NYSEG			See Calc Below
			RG&E			See Calc Below
	(E) Projected Labor Cost Savings	Electric Op	NYSEG	[redacted]		WR X Job-Hours Saved
			RG&E			WR X Job-Hours Saved
		Gas Op	NYSEG			WR X Job-Hours Saved
			RG&E			WR X Job-Hours Saved
		Total		[redacted]		**Expected Cost Savings**

[redacted]

Table 2 - Cost Savings from 3% Productivity Improvement
Back-up to CBA 5.1
Monitoring Field Job-Hour Expenditures by Including Planned Job-Hours in Work Packages

Assumptions on Percent of Work Planned: 100% Capital, 70% O&M

Resource	Description	Operations	OpCo	Capital	O&M	Remarks
Internal	(A) Total 2010 Actual Job-Hours	Electric Op	NYSEG	12,853	535,237	DRs # 934 & 936
			RG&E	15,122	153,461	DRs # 935 & 937
		Gas Op	NYSEG	8,695	237,240	DRs #954 & 956
			RG&E	676	179,288	DRs #955 & 957
	(B) Percent of work Planned	Electric Op	NYSEG	12,853	374,666	100% Cap; 70% O&M
			RG&E	15,122	107,423	100% Cap; 70% O&M
		Gas Op	NYSEG	8,695	166,068	100% Cap; 70% O&M
			RG&E	676	125,502	100% Cap; 70% O&M
	(C) Projected Job-Hour Savings (3% Improvement)	Electric Op	NYSEG	386	11,240	3% on Planned Work
			RG&E	454	3,223	3% on Planned Work
		Gas Op	NYSEG	261	4,982	3% on Planned Work
			RG&E	20	3,765	3% on Planned Work
	(D) Wage Rates (WR)	Electric Op	NYSEG	[redacted]		See Calc Below
			RG&E			See Calc Below
		Gas Op	NYSEG			See Calc Below
			RG&E			See Calc Below
	(E) Projected Labor Cost Savings	Electric Op	NYSEG	[redacted]		WR X Job-Hours Saved
			RG&E			WR X Job-Hours Saved
		Gas Op	NYSEG			WR X Job-Hours Saved
			RG&E			WR X Job-Hours Saved
		Total		[redacted]		**Expected Cost Savings**

Table 3 - Cost Savings from 5% Productivity Improvement
Back-up to CBA 5.1
Monitoring Field Job-Hour Expenditures by Including Planned Job-Hours in Work Packages

Assumptions on Percent of Work Planned: 100% Capital, 70% O&M

Resource	Description	Operations	OpCo	Capital	O&M	Remarks
Internal	(A) Total 2010 Actual Job-Hours	Electric Op	NYSEG	12,853	535,237	DRs # 934 & 936
			RG&E	15,122	153,461	DRs # 935 & 937
		Gas Op	NYSEG	8,695	237,240	DRs #954 & 956
			RG&E	676	179,288	DRs #955 & 957
	(B) Percent of work Planned	Electric Op	NYSEG	12,853	374,666	100% Cap; 70% O&M
			RG&E	15,122	107,423	100% Cap; 70% O&M
		Gas Op	NYSEG	8,695	166,068	100% Cap; 70% O&M
			RG&E	676	125,502	100% Cap; 70% O&M
	(C) Projected Job-Hour Savings (5% Improvement)	Electric Op	NYSEG	643	18,733	5% on Planned Work
			RG&E	756	5,371	5% on Planned Work
		Gas Op	NYSEG	435	8,303	5% on Planned Work
			RG&E	34	6,275	5% on Planned Work
	(D) Wage Rates (WR)	Electric Op	NYSEG	[redacted]		See Calc Below
			RG&E			See Calc Below
		Gas Op	NYSEG			See Calc Below
			RG&E			See Calc Below
	(E) Projected Labor Cost Savings	Electric Op	NYSEG	[redacted]		WR X Job-Hours Saved
			RG&E			WR X Job-Hours Saved
		Gas Op	NYSEG			WR X Job-Hours Saved
			RG&E			WR X Job-Hours Saved
		Total		[redacted]		**Expected Cost Savings**

We estimate implementation costs at $20K for SAP upgrades, and production of benefits: $1.0 to $1.5 million annually after first year

3. **Enhance the cost estimating capability by establishing a structured cost estimating program.** *(Conclusions #15 and #16)*

This recommendation focuses in the key elements of cost estimating that need improvement:

- The Process – There are no established processes, and hence, the cost estimates prepared by different individuals could be inconsistent.
- The Methods - Documentation of major uncertainties or variable components of a cost estimate, such as scope definitions, bases, assumptions, qualifications, and exclusions that affect the final cost is usually lacking.
- The Tool - Compatible Unit has not been adequately maintained and updated.
- The Philosophy - There is no review of prepared estimates by the field supervisors, no estimate accuracy expectation, and also no requirement to reconcile the project final costs

that overrun the original authorized project estimate substantially to understand project cost growth.

- The Resources - There are no full-time cost estimators.

Liberty recommends the Company to develop an effective cost estimating capability by implementing the following four initiatives:

a) Develop a Cost Estimating Manual (or guidelines) with the following objectives:
    - Explain all the cost estimating processes in order to enhance the general acceptance of the estimated cost and proper management of physical work of all sizes.
    - Establish the Company's philosophy regarding to the types of estimates and their purposes, the differentiation of estimate quality (accuracy), and the review requirements that are essential to make the estimates credible.
    - Standardize the cost estimating methods of the various types of Electric and Gas Operations work.
    - Delineate the basic concepts of estimating and explain various estimating terms such as direct costs, indirect costs, unit installation rates, wage rates, material pricing, and overheads, contingency.
    - Define the roles and responsibilities of all individuals contributing to the development of a credible estimate.

b) Resume the update and maintenance of the Compatible Unit on a periodic basis.
c) Transfer the responsibility of overseeing the Cost Estimating function to the Director of Cost Management to maintain the sharpening of cost estimating skills and maintaining data integrity of all the estimating databases.
d) Establish a centralized cost estimating group of four cost estimators (two each in RG&E and NYSEG to support Electric and Gas Operations work) reporting to the Director of Cost Management.

The principal implementation costs will involve:

a) Developing Cost Estimating Manual – One Electric Operations engineer and one Gas Operations engineer for six months each: (+$150K total) the major scope of work is to formalize all the existing cost estimating methods on Electric and Gas Operations projects and various types of routine work
b) Updating Compatible Unit – One Electric Operation engineer and one Gas Operations engineer for six months each annually (+$150K annually); could be funded from vacant positions since this is an old function that has been discontinued
c) Transferring overseeing responsibility of cost estimating function to the Director of Cost Management – No incremental costs
d) Establishing a cost estimating group of four cost estimators – ($400K total annually); could be funded from existing positions (planners or engineers) since this is a transfer of existing functions; there should also be a reduction of engineer contractor costs from the firm currently providing cost estimates for the projects designed by its engineers.

The benefits of implementation can be summarized as follows:

- Credible cost estimates are crucial cost control baselines. Cost estimates are used for project commitment, budget development, and funding authorization. Well prepared cost estimates will enhance analysis when the actual costs start to deviate from the original expectation.

- More effective cost estimating capability will also enable the Company to perform confidently the following functions: cost impact assessment in project scope growth, contractor bid evaluation, cost savings resulting from continuous improvement initiatives, year-end O&M forecast, evaluating contractor cost change requests, among others.
- A sound cost estimating process will guide the designers, the project managers, and construction supervisors to better scope out the physical work and identify as many uncertainties as practical at the time. This will aid in overall cost control, as all the individuals involved in the project will be mindful of potential cost drivers.
- A disciplined cost estimating process also leads to the documentation of many factors and assumptions involved at a particular moment in time. They can then be compared and analyzed, contributing to the learning experiences that build up the managerial skills needed for effective business decisions.
- A cost estimate is more than just a number. A well-documented presentation of a cost estimate communicates the bases and assumptions behind the cost figure and will minimize any misunderstanding or perception of misrepresentation.
- The estimate review step is a strong promotion of cost culture since design engineers and construction supervisors will have a role in providing input during development of estimates. It is only fair to the construction supervisors, who have to manage the production and productivity.
- With the availability of full-time cost estimators, the designers can concentrate on engineering, the planners on project planning, and construction supervisors on managing field work.

C. Resource Management

1. Background

Effective resource management encompasses the planning, development, deployment and facilitation of a skilled, productive work force. Liberty’s evaluation focused on the physical work force. In evaluating the management of the physical workforce, we examined a number of key factors. The first was supervision effectiveness, as the planners and supervisors play a key role in work performance. Other areas examined included safety and training program, work rules and labor agreements, crew size and structure, overtime and shift strategies, and contracting strategies and practices.

The criteria by which Liberty evaluated resource management included the following:

- Supervision should effectively function to facilitate the work, including assurance of adequate personnel, support resource where necessary, material availability, management of travel and other downtime, completeness of work packages, crew instructions, safety measures and all other local facilitation activities.
- Training requirements for physical workers should be formally defined and compliance should be monitored.
- Standard crew sizes, or crew structure tailored to specific projects, should be optimal.

- Management should emphasize the need for efficient work rules and practices in labor agreements and ongoing negotiations.
- A formal safety program should be in place, with suitable oversight by an independent organization.
- Guidelines for the scheduling of overtime should be in place to prevent excessive overtime during normal operations. Similarly, guidelines for shift strategies for multi-shift operations should be in place.
- The Company's labor contracting strategy should be defined and should provide for the optimum use of the Company's fixed resources.
- Lesser cost resources should be used for "low end" work (flagging, digging, material delivery, clean up, for example) in order to optimize use of skilled resources.

2. Findings

a. Supervision Effectiveness

In the analysis of productivity and work force effectiveness, the role of supervision is often misunderstood. Conventional thinking often suggests that effective supervision means getting the maximum effort from people by pushing them hard, enforcing work rules and demanding a maximum effort at all times. In reality, supervision can produce real productivity gains more from facilitating the work than from “bossing” the worker.

Effective supervisors have to know their crews well, and assign tasks to the workers with the right skills. By assuring that workers are prepared for the work, that materials are readily available, that engineering information is in place, that the work package is adequate, and that safety considerations have been discussed, supervisors allow crews to perform at their optimum, without undue interruption.

i. Supervisory Ratios

Effective supervision is crucial to efficient work force management. Supervisory ratio gives an indication if the supervisor coverage is adequate. The nature of the work and the size of the geographical areas demand varying degrees of supervisory requirements. The supervisory ratios of the NYSEG and RG&E are summarized as follows:

- For Gas Operations – NYSEG ratio is 1:11and RG&E ratio is 1:15 to 1:20
- For T&D work – NYSEG ratio is 1:11and RG&E ratio is 1:15 to 1:20
- For Substation work – NYSEG ratio is 1:14 and RG&E ratio is 1:14

In Gas Operations and T&D work, RG&E figures are higher, due to a more concentrated service territory.

ii. Supervisors’ Qualifications

The major responsibilities of a supervisor are to oversee, plan, and schedule new construction work, preventive and corrective maintenance, inspections and training activities. The goal is to ensure that construction and maintenance work is completed in accordance with construction standards, approved policies, procedures, safety rules and budgets. The supervisor often has to interact with customers to solve problems or concerns, and ensure customer satisfaction. Additional responsibilities include emergency restoration, coordinating safety training, documentation, inspections, and accident investigations. Such job requirements demand special skills, relevant experiences and technical education.

The qualifications and experiences required for selecting supervisors are adequate. For Electrical or Gas Operations supervisors, the requirement is at least five years of related Construction and Maintenance experience in Transmission and Distribution for Electric Operations supervisors or gas mains and service work for Gas Operations supervisors. They are also required to have extensive knowledge in their line of work of: labor agreement, safety manual, electric theory or leak detection methods, tagging, switching, blocking, procedures, and instrumentation. They must also be familiar with industry codes and OSHA safety requirements. For certifications, they may require various DOT Operator Qualifications. For education, they need to be high school graduate or equivalent years of experience. Associate degrees in related technology area are preferred.

The processes to fill in-house positions and recruit external candidates are comprehensive. For internal positions, the Company has developed a Career Opportunity Announcement Program to enable employees to become aware of and apply for non-union promotional and developmental opportunities. Candidates that respond to the postings are screened, interviewed, and selected with assistance from Human Resources Department.

It is the policy of the Company to fill job openings with the most qualified person available. When no in-house candidate qualifies for the position, the responsibility for initiating action to fill a job opening externally rests with the respective managers and business area leaders. Appropriate business area leaders, department managers, and others in managerial positions will approve all who will work in their respective jurisdictions. The Human Resources Department will assist the organization in finding the best qualified person for the job opening, assure that the Company complies with all relevant regulations in employment, and ascertain adherence to Company policy.

The interfaces with supervisors during our field visit confirmed that the supervisors of Electric Operations, Gas Operations and Mobile Work Force are all very knowledgeable and effective in managing their crews.

iii. Interviews and Field Observations

To understand the roles and responsibilities of the supervisors, Liberty interviewed three supervisors in that role. In addition, the following activities were observed in the field:

a) Electric Operations: Replacing pole with new re-closer design
b) Gas Operations: Investigating leaks discovered on walk-down, service renewal for resident, and third party damage on gas line by house owner's plumber
c) Mobile Work Force: Installing a new 34.5kv line to a gas compression station.

The following criteria were applied: daily tailboard meetings, completeness of work packages, crew size, supervisor's interfaces with work crews, fleet size, safety consciousness, potential material issues, required technical support, low-end work, and implementation of physical work.

The following common issues were identified:

a) Work Planning: No mention of authorized or expected work hours
b) Resource Management: No plan to replenish departed workers; crews from RG&E and NYSEG seldom work in each other's territories
c) Performance Measurement: No measurement of productivity; little management review of field productivity
d) Cost Management: No real time management of labor cost; no requirement to analyze cost and productivity in the field.

b. Training Requirements of Workers

The Company has instituted a set of comprehensive training modules to establish a career path for its work force. The duration for an Electric Operations apprentice to become fully qualified is three and a half years, with a total of 179 training courses to be taken. This line progression training consists of 7,280 hours (736 hours at the training facility and 6,544 hours in the division).

The duration for a Gas Operations apprentice to become fully qualified is three years. A total of 51 training modules will have to be taken within that timeframe. The line progression training consists of 360 training hours and three years of on-the-job training.

c. Crew Management

i. Crew Size and Structure

The crew size and structure vary with the tasks performed. The table below summarizes the typical crew structure:

Company	Operations	Function	Crew Size
NYSEG	Electric	Electric Overhead Line Crew	2
		Electric Meter Technician	1
		Electric Pole Setting or Pole-hole Crew	2
		Street-lighting Crew	1
		Electric Single Worker	1
		Electric Transmission Construction Crew	7
		Electric Trouble Shooting Crew	1
		Electric Underground Cable Crew	4
		Electric Tree Trimming Crew	2
		Service Center Crew	2
		Substation Construction & Maintenance Crew	2
		Substation Protection & Control (Relay) Crew	1
RG&E	Electric	Electric Low Voltage Trouble & Maintenance Technician	1

		Electric Meter Technician	1
		Electric Overhead Line Crew	2
		Electric Pole Setting or Pole-hole Crew	4
		Electric Subway Crew	1
		Electric Subway Inspector	1
		Street-lighting Crew	2
		Electric Single Worker	1
		Electric Transmission Construction Crew	5
		Electric Transmission Line Inspector	1
		Electric Trouble Maintenance & Repair Crew	2
		Electric Underground Cable Crew	2
		Service Center Crew	4
		Substation Construction & Maintenance Crew	4
		Substation Equipment Shop Crew	2
		Substation Protection & Control (Relay) Crew	2
		Substation SCADA Crew	2
		Substation Traveling Switchman	1
		Substation Maintenance Tester	1
NYSEG	Gas	Gas Construction & Maintenance Crew	4
		Gas Corrosion Inspection	1
		Leak Survey Crew	1
		Gas Operations Technician	1
		Gas Regulation & Pressure Control Crew	2
		Gas Service Construction Crew	3
		Gas Tie-in Crew	4
		Gas Valve Inspection	2
		Gas Welder	1
RG&E	Gas	Commercial and Industrial Meter Crew	2
		Gas Construction & Maintenance Crew	3
		Gas Construction & Maintenance Worker	1
		Leak Survey Crew	1
		Gas Regulation & Pressure Control Crew	2
		Gas Residential Meter Crew	1
		Gas Tie-in Crew	2
		Gas Turn-on and Shut-off Crew	1
		Gas Welder	1

The Company has the flexibility to determine the crew size for specific jobs. Some low-end work is contracted when feasible. During Wave 2 of the Rapid Results Program, the Company was able to implement the single worker unit (SWU) and First Responder (FR) initiatives to reduce the number of steps in the call out process. This implementation resulted in clearing 40 percent of the trouble tickets with half of the associated labor and fleet costs.

ii. Resource Relocation

The contract provisions allow the Company, given certain parameters and limitations within the contract, to temporarily reassign employees, or allow them to volunteer, to perform work in another region, whether it is routine or emergency.

The work crews, however, seldom cross over between NYSEG and RG&E service territories. This is confirmed by an examination of the 2010 time charges on both Companies.

iii. Resource Requirement Planning

The Company in the past did not have an effective tool to assess a longer term resource requirement to meet changing workloads. The Company is currently developing the IUSA Line Worker Workforce Model as a resource planning tool. It has the essential features to match resource supply versus work demand. This model appears to work well in Central Maine and is in the process of being implemented in New York. If this model works well for line work, it will be extended to Gas Operations in the future.

d. Efficient Work Rules and Labor Agreements

The current agreement, based on the Collective Bargaining Agreement between Local Union No. 36 IBEW and RG&E (as a subsidiary of Energy East), is dated September 1, 2003 to May 31, 2008. This agreement was continued to May 31, 2013 under a Memorandum of Agreement between the parties, with new terms covering wages, pension, 401 (k) Plans, retiree medical benefits, management rights and responsibilities, work hours, safety and work rules.

The current agreement, based on the Collective Bargaining Agreement between System Council U-7 (representing Local Unions No. 83, 249, 966 & 1143) and NYSEG (as a subsidiary of Energy East), is dated July 1, 2005 to June 30 2010. This agreement was continued to June 30, 2015 under a Memorandum of Agreement between the parties, with new terms covering wages, pension, 401 (k) Plans, and retiree medical benefits.

In accordance with the current terms of Agreements and Memoranda, the following provisions offered the Company flexible work rules and favorable agreements to enhance operational efficiency: weekly schedule change, call-in for emergency service, contracting out work, working in inclement weather, promotion, no strikes-no lockouts, and work schedule exceeding consecutive hours.

e. Safety Program

i. Safety Policies

The Company expresses consistently a commitment to safety, and defines the same requirements for both NYSEG and RG&E. All workers in Electric Operations are to follow the Accident Prevention Manual, Occupational Safety and Health Administration Standard¸ and National Electric Safety Code (NESC). All workers in Gas Operations are to follow the Accident Prevention Manual, Health and Safety Administration Guidelines, and Gas Operating and Maintenance Procedures.

ii. Independent Safety Oversight Organization

The safety oversight department is organizationally independent from all the work groups it supports. There are four dedicated employees for RG&E and three for NYSEG. They report to the Environmental, Health and Safety (EHS) Compliance Managers of the respective Companies, who reported to the Director of Compliance. The Department of Compliance is under Human Resource (HR). The VP of HR reports directly to the Chief Executive Officer. The Safety Oversight Organization is an independent group, but is relatively small and placed low in the corporate hierarchy.

iii. Safety Training Program

The training program is extensive and comprehensive. In addition to some one-time courses, there are refresher courses that must be taken annually or on different yearly cycles as summarized below:

Safety Training Courses

Business Area	No. of Courses						
	Initial Training	Annual Cycle	2 Year Cycle	3 Year Cycle	4 Year Cycle	8 Year Cycle	Total
Gas Operations	6	8	1	14			29
T&D Line	7	7	2	12	3	2	33
Substation	8	9	2	14	2	2	37
Transportation	4	2			8	1	15

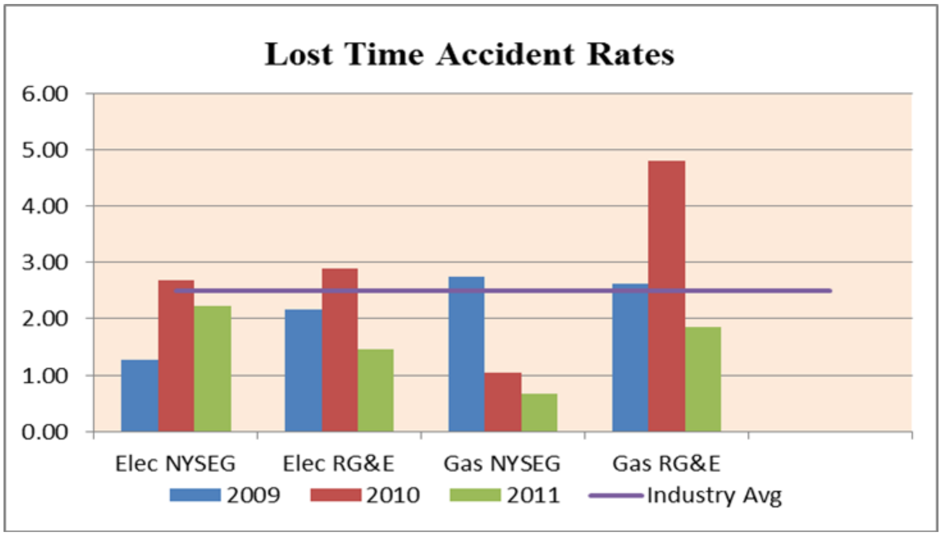
The following table on the initial training courses among the four business areas will give an indication about the safety focuses:

Course	Gas	T&D Line	Substation	Transportation
Accident Prevention Signs and Tags	X	X	X	X
Asbestos Awareness	X	X	X	
Asbestos Substation Control Wiring			X	
Compressed Gas Cylinder Safety	X	X	X	X
Fall Protection (Platforms and Stairs)	X	X	X	X
Forklift Truck Safety	X	X	X	X
Hazmat Technicians	X			
E-STAR Switching and Tagging		X	X	
E-STAR Mark-Up		X	X	

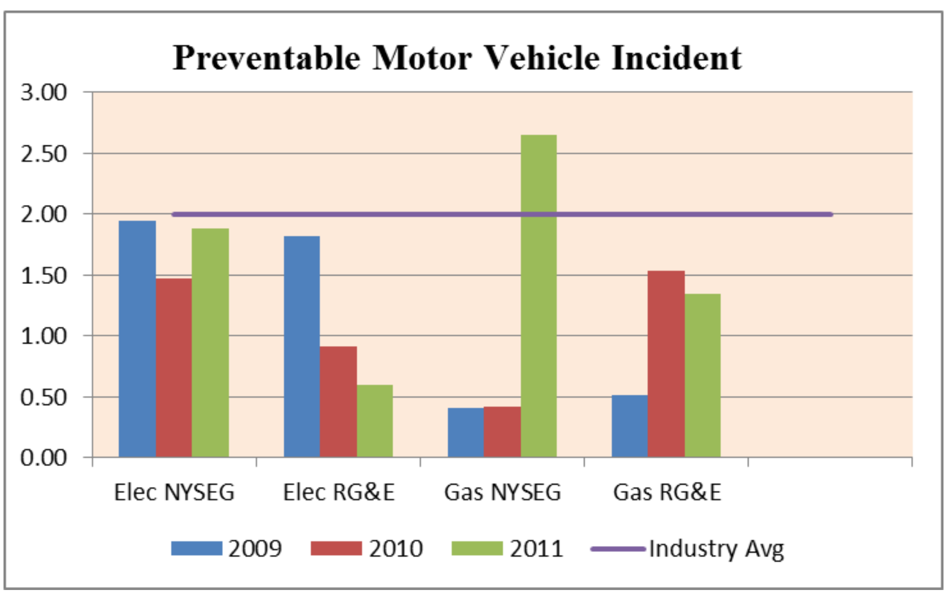
iv. Safety Metrics

Safety statistics often show as part of organizational key performance indicators. The Company has placed high priority on Safety. We examined key safety performance metrics. It should be noted that the "Industry Average" is inserted for reference purpose only, and is not meant to be a measurement target, because there are such diversities in organizational make-up. For example, the RG&E Gas Operations organization is a small organization. One additional incident will affect the result substantially. Nevertheless, the industry standard definition is intended to normalize all the variations for comparison. The strategy is to minimize or eliminate potential incident such that such variation issues could be rendered irrelevant.

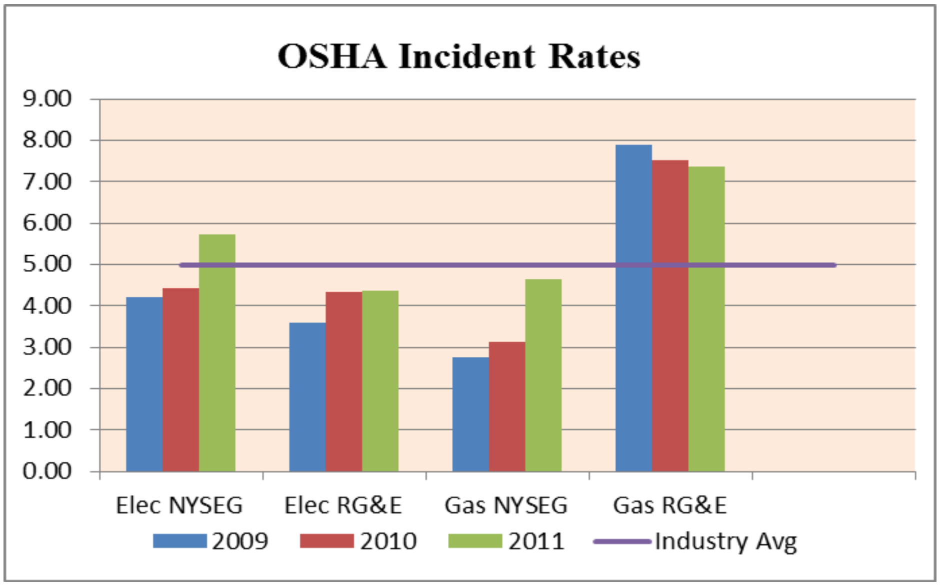
The Lost Time Accident Rates metric reflects favorable results except for Gas RG&E in 2010.



The Preventable Motor Vehicle Incident Rates metric shows comparable results except for Gas NYSEG in 2011 (even though 2011 was not yet over, but too many accidents occurred for this work group to recover).



The OSHA incident rates of RG&E Gas Operations is consistently high for the last three years. Also, the OSHA incident rates of NYSEG are trending higher for Electric and Gas Operations for the last three years.



For ease of monitoring purpose, a new safety metric, known as Combined Safety Index was developed. It summarizes, by Operating Company data including total injuries, lost time injuries, preventable motor vehicle incidents, and lost days for all the major departments, such as Electric Operations, Gas Operations, Engineering & Asset Management, Customer Services, General Services, and Human Resources. Comparing the performance over the last three years is inconclusive, as the index has gone through some modifications during that period. The metric would be a simple effective tool to monitor future safety performance at a global level.

New York State Electric & Gas	2011						2011 "Effective" Goal (5-Year Best)				
Line of Business	Total Injuries	Lost Time Injuries	Motor Vehicle Incidents	Lost Days	Total CAR/PARs	Combined Safety Index	Total Injuries (2010)	Lost Time Injuries (2009)	Motor Vehicle Incidents (2010)	Lost Days (2010)	CAR/ PARs (2010)
NYSEG Sept 2011 (FINAL)	**66**	**28**	**26**	**1169**	**87**		**73**	**27**	**36**	**1327**	**86**
CSI Sept 2011 (FINAL)	**1.4**	**1.4**	**0.8**	**1.4**	**0.8**	**5.8**					
10/21/2011 YTD (Preliminary)	**1.4**	**1.4**	**1.0**	**1.4**	**0.6**	**5.8**					
NYSEG	**70**	**28**	**29**	**1220**	**121**		**73**	**27**	**36**	**1327**	**86**
Electric Ops	36	14	12	549	62		40	11	12	837	46
Gas Ops	7	1	5	6	11		7	5	1	45	8
Engineering & Asset Mgt	1	0	0	0	3		2	0	1	0	2
Customer Service	24	12	11	510	37		20	8	21	242	24
General Services	1	1	1	155	6		4	3	1	203	6
Human Resources	0	0	0	0	0		0	0	0	0	0
IT	0	0	0	0	0		0	0	0	0	0
President's Office (NYSEG)	1	0	0	0	2		0	0	0	0	0

Note: OSHA Total Injury Rate and Lost Time Injury Rate are normalized by 100 employees. MVI Rate is normalized by million miles driven. CSI is not affected by headcount changes. 2011 Goals as noted were established based on 5-year best performance. Goals must be achieved in order to meet CSI = 5.0

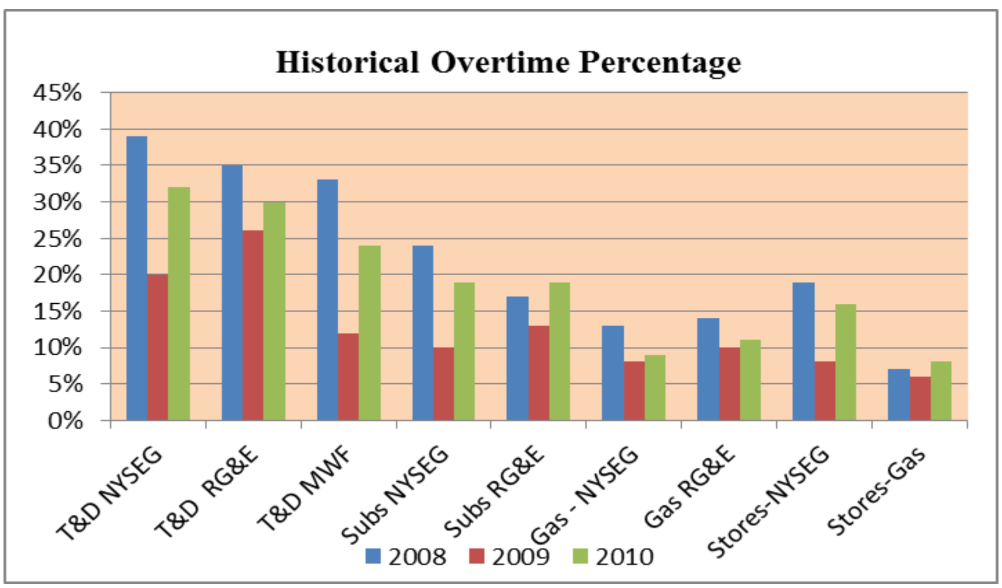
Rochester Gas & Electric	2011						2011 "Effective" Goal (5-Year Best)				
Line of Business	Total Injuries	Lost Time Injuries	Motor Vehicle Incidents	Lost Days	Total CAR/PARs	Combined Safety Index	Total Injuries (2010)	Lost Time Injuries (2010)	Motor Vehicle Incidents (2010)	Lost Days (2010)	CAR/ PARs (2010)
RG&E Sept 2011 (FINAL)	**22**	**5**	**4**	**138**	**55**		**27**	**15**	**10**	**334**	**31**
CSI Sept 2011 (FINAL)	**1.4**	**0.6**	**0.6**	**0.6**	**0.6**	**3.8**					
10/21/2011 YTD (Preliminary)	**1.4**	**0.6**	**0.6**	**0.6**	**0.6**	**3.8**					
RG&E	**25**	**5**	**5**	**138**	**61**		**27**	**15**	**10**	**334**	**31**
Electric Ops	9	3	1	114	35		11	8	2	247	16
Gas Ops	10	2	3	24	12		10	6	3	80	10
Engineering & Asset Mgt	0	0	0	0	2		0	0	1	0	0
Customer Service	3	0	0	0	7		5	1	1	7	4
General Services	2	0	1	0	4		1	0	3	0	1
Human Resources	0	0	0	0	0		0	0	0	0	0
IT	0	0	0	0	0		0	0	0	0	0
President's Office (RGE)	1	0	0	0	1		0	0	0	0	0

Note: OSHA Total Injury Rate and Lost Time Injury Rate are normalized by 100 employees. MVI Rate is normalized by million miles driven. CSI is not affected by headcount changes. 2011 Goals as noted were established based on 5-year best performance. Goals must be achieved in order to meet CSI = 5.0

f. Guidelines for Overtime and Shift Strategies

The Company has an overtime pay policy, but no overall directives regarding overtime management policy. It basically delegates the authority to the local managers and supervisors to approve overtime on an as-required basis. There is little analysis on overtime. The overtime level does not appear in any performance metrics that have been provided. There is also no documented review of overtime at any level.

A historical look at the percent of overtime (inclusive of Capital and O&M as well as routine and emergency responses) of the physical workers among the various work groups for the past three years yields the following results:



Our observations on historical overtime levels are:

- For Gas Operations, both NYSEG and RG&E have maintained their overtime at an acceptable level of around 10 percent.
- T&D Overtime levels for both NYSEG and RG&E are consistently at an unacceptably high level for the past three years. In 2010, it is 32 percent for NYSEG (48 percent in Brewster, 51 percent in Mechanicville, and 42 percent in Liberty regions) and 30 percent for RG&E (39 percent in Canandaigua, 29 percent each in Sodus and Rochester).
- Likewise, Mobile Work Force (MWF) of NYSEG has doubled their overtime from the previous year to 24 percent. Due to low traveling compensation for the crews, MWF is having difficulty recruiting linemen to join its organization.
- For Substation work, both NYSEG (Brewster 28 percent, Elmira 27 percent, Mechanicville 24 percent, Liberty 24 percent, Ithaca 23 percent and Lancaster 22 percent) and RG&E have also increased the overtime significantly from the previous year to 19 percent. NYSEG almost doubles doubled due probably to 18 percent attrition, while RG&E went up 50 percent due probably to more production.
- Stores overtime level in 2010 is double the previous year at 16 percent.
- All business areas appear to be trending up in 2010 towards the high level of 2008.

Gas Operations has implemented in 2010 a process improvement initiative to reduce the O&M overtime by 20 percent under Wave 2 of Rapid Results.

Electric Operations has implemented in late 2010 a process improvement initiative to reduce the O&M overtime by 20 percent under wave 3 of Rapid Results.

The Company presently does not have a regular second shift for physical work, and has no shift policy. The IUSA Line Worker Workforce Model that the Company is developing has Shift Analysis capability to simulate whether it is more cost effective to work overtime versus staffing a second shift.

g. Contracting Strategies and Practices

i. Contracting Strategies

Designers or engineers decide what work to contract out based on skill requirements, in-house resource availability and date required. Work assigned to the field might be contracted if supervisors decide that the crews are not available or do not have the proper skill to meet the required deadline.

ii. Approach to Contracting Physical Work

In deciding whether to contract the work, the basic determination is to evaluate available resources (internal versus external) along with timing, existing work volume, and complexity of the jobs.

For Gas Operations, the Company work force will focus on core work tasks (emergency response, mandated O&M work, leak surveys, leak repairs, contractor inspections, for example) and contract most capital construction and a portion of the underground locating services.

For Electric Operations, the Company work force will focus on regular work (*e.g.*, emergency response, customer service work, distribution minor capital, routine operations and maintenance) and assign some capital work to Mobile Work Force. The Company will contract out major capital projects, specialty work (*e.g.*, cable curing, stray voltage testing, pole hauling) and unit pricing work (*e.g.*, pole inspection, manhole leveling) when it is cost-effective to do so.

When schedules need to be met, both Electric and Gas Operations will employ contractors. Resources from other IUSA Operating Companies are seldom considered.

iii. Indirect Costs associated with Contractors

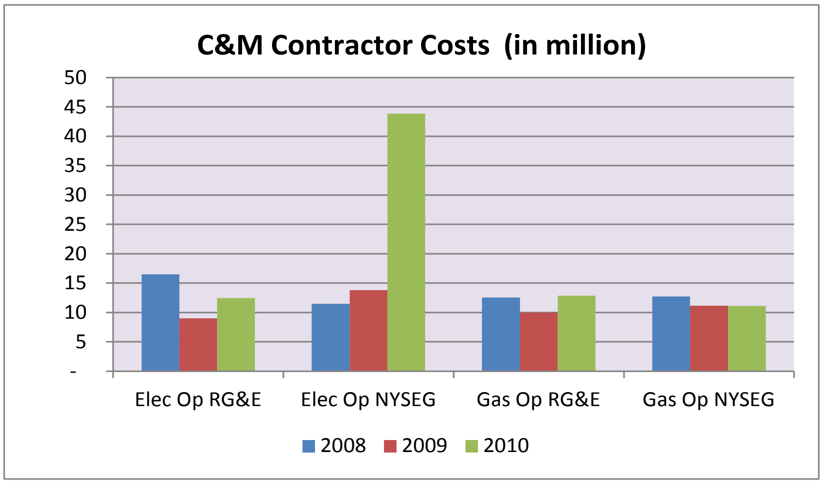
The determination of contractor costs is based on the estimate provided by contractors themselves, or on historical information. There are no internal costs added to projects related to contract management or related to the development of the contracts themselves.

All costs related to the development and engagement of contracts is collected by the purchasing group at IUMC and allocated to the operating Companies based on the specific work being performed on behalf of the operating Companies. These costs are not included in capital, but are instead included wholly in O&M expense as part of the shared service allocation. The internal cost or overhead for contract management, contractor support (including warehousing), and other direct and indirect costs associated with the Purchasing process are allocated in two different ways: (a) through a global allocation to the operating Companies, or (b) through direct charges to certain capital projects.

Gas Construction Inspectors and the supervisor directly involved with the project will account for their time directly to the capital project work order number for their time associated with the project. Electric supervisors and contingent based workers of NYSEG overseeing contracted work charge their time to a clearing cost collector.

iv. Contractor Management

For Gas Operations work, there was a 28 percent increase in using contractors for RG&E, but no change in NYSEG. For Electric Operations work, there was a significant increase in using contractors, 38 percent for RG&E and more than tripled for NYSEG, due probably to capital projects in Ithaca and Elmira.



In 2010, the collective contractor costs for Electric & Gas Operations doubled the previous year, reaching $80 million.

v. Contractor Safety Requirements

For Electric Operations, all contractors have to adhere to the document "Contractor Safety Requirements for Services Provided to Iberdrola USA Affiliate Companies." This document summarizes all the corporate safety compliance programs, standard operating procedures, and all the federal and New York State rules/regulations regarding to safety.

For Gas Operations, a Blanket Contractual Agreement Safety Rules and Regulations is included as an appendix in every contract, along with a Contractor Safety and Health Obligations document.

vi. Contractor Supervision

Supervisors or contracted contingent based workers monitor the work of contractors. Contractors provide rework at their own expense or the Company holds back payment until restitution is made by the contractor. In some cases, a contractor will be billed for the cost of the contractor's error.

vii. Contractor Performance

At the completion of each contract, the supervisor will fill out a Contractor Performance Scorecard that focuses on the four main areas of Environmental, Health and Safety (EH&S), Quality, Timing and Cost:

- For EH&S, the areas rated are OSHA reportable incidents, DEC/DOT Compliance, Conformance to all government rules/regulations and job site safety inspection.
- For Quality, the areas rated are customer complaints, reworks, adherence to safety standards, third party outages, third party damages, and calls to dig-safe.
- For Timing, the areas rated are meeting project schedule and invoice submitted for payment within 30 days.

- For Cost, the areas rated are accurate invoice submission, work completed per contract, not-to-exceed price, cost associated with material damages, unauthorized change orders, contractor change order requests, and third party damages.

The outcomes of the rating on the above criteria are: (a) satisfactory, or (b) unsatisfactory only.

viii. QA Inspection of Contractor's Work

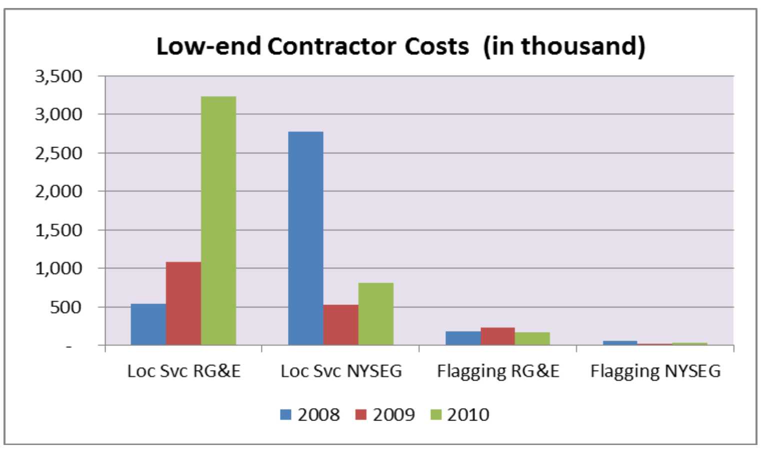
QA/QC will issue Supplier Corrective Action Reports (SCAR) for material issues and Non-Conformance Reports (NCR) for field installation issues per QA Manual. Contractors will have to make remedy at their own expenses.

For Gas Operations, the QA/QC acceptance rate had been very good at 99.4 percent in 2008, 99.0 percent in 2009, and 98.8 percent in 2010. This data was based on about 2,500 inspections per year.

For Electric Operations, there were no QA acceptance rates, as there was no official QA function. IUSA relies on the final inspection of supervisors or contracted contingent based workers for assurance of proper work completion.

h. Lesser Cost Resources for Low-End Work

Flagging and Locating Services are the only low-end production field work contracted out in both Electric Operations and Gas Operations.



The total costs of Flagging work were relatively stable for both NYSEG and RG&E for the past three years. The level of Locating Services has tripled in 2010 for RG&E.

i. Observations on Customer Service Staffing

Liberty interviewed IUSA's VP of Customer Service and both the Binghamton and Rochester call center managers. Additionally, Liberty toured the two New York call centers and requested and reviewed a dozen documents detailing contact center performance and staffing. Staffing levels were discussed during all interviews, especially in light of the contract changes and early retirement programs offered in mid-2010.

While staffing levels did drop in the NYSEG contact center during mid-2010, NYSEG customer service management took a number of actions to ensure that it continued to meet service level answering targets for 2010 and 2011. Well prior to the changes, IUSA developed Operational Readiness Plans detailing actions to minimize the impact of staffing changes and reductions. Specifically, IUSA increased web and IVR self-service options for customers, promoted and increased eBill adoption, set up provisions to bring in other department resources (Billing) when needed, and outsourced more calls to IQOR. Additionally, IUSA reduced incoming call volume through several "rapid results" projects and continues to pursue options to reduce call volume with a focus on first call resolution.

NYSEG and RG&E contact centers staff and manage to service level objectives. Both centers rely on workforce management teams to forecast call volumes, schedule staff, and actively monitor and adjust staffing on an intraday-basis to meet service level objectives. NYSEG and RG&E have also met annual call center service level targets in 2010 and 2011, as defined by the rate plan.

Both RG&E and NYSEG have storm response plans in place to guide the centers during large outages and storms. IUSA's IVR has sizeable capacity (382 ports) to support high-volume automated outage reporting and inquiry. The storm plans also detail staffing options to pursue based on the size of the storm. In addition to calling in or holding over representatives, IUSA will also tap into secondary resources to supplement staffing, including other customer service departments such as Billing and Collections, as well as its outsourcers. IUSA also contracts with [redacted] for after-hours outages. [redacted] live agents have the capability to create outage tickets and respond to customer inquiries.

3. Conclusions

19. Qualifications and experiences required of supervisors are appropriate; supervisors respond actively to construction issues and resource needs in the field; supervisory ratios for both NYSEG and RG&E work are all bordering on the high end of the industry range.

During the interview sessions and field visitations, our observation was that all the supervisors and planners were knowledgeable about their work and possessed diversified experiences. The work packages included adequate information to proceed with the execution of the jobs. The supervisors provided essential crew instructions during the morning tailboard sessions as well as job briefings at the work site. They also provided on-the-job coaching to the trainees, as warranted. There were no material availability problems. Supervisors or planners effectively requisitioned materials for crew pick-up or arranged for site delivery of large components. However, most of the supervisory ratios for both NYSEG and RG&E work are all bordering on the high end of the industry ranges of 1:12 for electrical work and 1:20 for gas work. The current supervisory ratio should be closely monitored. It should be considered unacceptable for this ratio to exceed the following thresholds: (a) NYSEG - 1:12 for T&D, 1:15 for Substation, 1:12 for Gas Operations; (b) RG&E - 1:20 for T&D, 1:15 for Substation, 1:20 for Gas Operations.

20. The training programs are generally adequate for physical workers.

The skill training requirements are extensive and inclusive. Apprentices reach full qualified status in 3.5 years for Electric Line Operations; 4.5 years for Electric Substation Operations; and 3.0 years for Gas Operations.

21. There is no effective resource plan to replace the aging work force. *(Recommendation #8)*

About 250 NYSEG craftsmen retired in the last three years, with about 100 apprentices hired. Sixteen craftsmen in RG&E retired in the last three years with no new replacements. A well-coordinated resource plan is needed; about 70 percent of NYSEG and over 50 percent of RG&E Electric and Gas operations work force is high-end experienced workers. It would take ten to twelve years for any good apprentices to reach that level.

22. There is a lack of long-term resource capability analysis; IUSA recognizes this need and has almost completed a work force planning model to plan for T&D Line work.

The Company has recognized the need for a robust work force planning tool to help the managers to identify work force needs in the future, to identify the gap between demand and supply for physical workers, and to make resource-related strategies. The Company has almost completed a work force planning model for line work. It will be extended to Gas Operations in the future.

23. The labor agreements by NYSEG with System Council U-7 of the IBEW and by RG&E with Local 36 of the IBEW provide sufficient flexibility and essential provisions for dynamic work force management. However, the 15 percent limitation on Mobile Workforce per NYSEG Memorandum of Understanding will affect its future expansion.

The labor agreements and work rules allow IUSA to have sufficient flexibility and provisions to manage the physical work in an efficient manner.

24. There is a reasonable degree of flexibility in structuring crew size and allocating resources.

IUSA can determine the crew size to implement field work. The Company also has the flexibility to reallocate resources to the proper work location without violating any collective bargaining agreements and the option to contract low-end work as appropriate.

25. The work crews from NYSEG and RG&E seldom cross over to work in each other's service territories, making resource use suboptimal. *(Recommendation #11)*

An examination of the 2010 time charges confirms that work forces from NYSEG and RG&E seldom performed work in each other's territories. It is an odd and potentially costly decision to use contractors rather than the work force from an affiliated company.

26. Assessments of productivity and cost impacts due to the replenishment of retired workers by apprentices are not being performed. *(Recommendation # 8)*

For more effective resource management, the productivity and cost impacts of replenishing retired workers by apprentices need to be continuously monitored and assessed. The Company is deferring the analytical capability to the newly developed IUSA Line Worker Workforce Model.

27. The OSHA incident rate of Gas Operations (excluding Gas Engineering) has been consistently high. *(Recommendation #5)*

The OSHA Incident Rate is defined as the number of OSHA recordable incidents/illnesses times 200,000 hours divided by the total hours worked. When the indicator is consistently at a high level, some investigations need to be conducted to identify the underlying causes on the types of injuries with high occurrences. Then the findings and lessons learned should be incorporated into future training sessions.

28. Overtime levels in Gas Operations are at a reasonable level but T&D overtime levels at both NYSEG and RG&E are very high and a source of concern. *(Recommendations #6 and #7)*

Gas Operations overtime is at about 10 percent. NYSEG and RG&E overtime both doubled from previous years and are at levels that raise concerns about the adequacy of internal resources and control of resource use. IUSA's current T&D overtime levels should be considered excessive and unacceptable. More importantly, it is reasonable to assume that the levels of overtime and management's inability to address this question suggest substantial underlying issues. A root cause analysis of this problem is very likely to reveal significant improvement opportunities for the Company.

29. The external resource requisition procedures are effective in securing competitive pricing.

IUSA's approach to using different types of contractors (*e.g.*, unit price, specialty, and low level) to supplement its work force is reasonable. The requisition and bid-evaluation processes also ensure competitive pricing.

30. In assigning physical work, IUSA has no articulated strategy or specific policies on balancing in-house and contractor resources. *(Recommendation #4)*

Although case-by-case contracting decisions seem to be made on a logical basis, the lack of corporate-wide direction on a contracting strategy is a weakness. An optimized work force requires a strategy for balancing resources, including specific definition of the role of contractors, management's desires for growth, stability or reduction of internal resources, cost trade-offs and overall objectives for using contractors.

31. The contractor work forces are generally efficient; there are many unit costing contractors and fixed price contractors.

The QA/QC acceptance rates were good. The Contractor Performance Scorecards in 2010 revealed no major unacceptable performance.

32. The substantial usage of contractors in Electric Operations underscores the question of the adequacy of internal resources. *(Recommendation #10)*

For Electric Operations work, there was a significant increase in using contractors, 38 percent for RG&E and a more than tripling for NYSEG. For better resource management and to avoid excessive use of contractors, periodic resource analysis should be performed at the global level to see if workload during peak periods can be shifted and levelized. The resource analysis can also reveal whether it is more effective to expand the internal IUSA work force in lieu of consistent contractor cost growth.

33. Contractor productivity is not monitored; the focus instead lies on work completion. (*Recommendation #9*)

Presently the contractors are managed by production only. Productivity is not a consideration as long as the projects or tasks get completed. There are no requirements in the contract agreements to report quantities of work completed or job-hours expended.

34. The Contractor Performance Scorecard is not alone sufficient to ensure contractor quality and compliance. (See *Recommendation #12 in the Performance Measurement section*)

At the completion of each contract, the supervisor fills out a Contractor Performance Scorecard that focuses on four main areas: safety, quality, timing, and costs. The outcomes of the rating on the above criteria are satisfactory or unsatisfactory only. Gas Operations has a QA/QC program that watches over contractor's performance. Electric Operations currently does not have such a program, but is in the process of developing a similar program as Gas Operations. When Recommendation No. 1 in the Performance Measurement section is implemented, there will be an independent group to manage and oversee the Electric Operations QA/QC program to monitor contractors' performance in a more effective manner.

35. The process of selecting supervisors is sound; the process to fill the position externally when no employees in-house are determined by management to be qualified is also acceptable.

There are comprehensive procedures that lay out the requirements to oversee the Company work force and contractors. There are comprehensive procedures and position guides that define the qualifications, education, and relevant work experience. It is also appropriate that the hiring managers will identify and ensure the personnel are qualified.

The same qualification and experience requirements apply to internal and external candidates. The Company will go outside only if no qualified internal candidates bidding on the posting are found. The same interview process is used for external candidates.

36. Low end work, such as flagging and underground location services, is appropriately outsourced.

Both Electric and Gas Operations have contracted out low end work when it is feasible and cost-effective to do so.

4. Recommendation

4. Establish a structured approach, policies and supporting guidelines for the balancing of in-house and contractor resources in physical work assignments. *(Conclusion #30)*

Work assignment does not now occur under a clear policy to balance in-house and contractor resources. Some guidelines, however, do apply:

- Electric Operations: For core work that requires appropriate skills and system familiarity, such as emergency response, customer service work, routine operations and maintenance, internal resources are used. For capital or large projects or tasks, available internal resources will be used first. Some may be assigned to Mobile Work Force. If the job cannot be deferred, external resources will be used. For projects less than $100K, pre-negotiated Master Service Agreement rates and a not-to-exceed (NTE) price are used from the next available contractor, if the NTE price does not exceed the estimated cost of the project. For projects larger than $100K, the project is put out to bid and the low bidder is awarded the project. For projects that require specialized skills or equipment, such as cable curing, stray voltage testing, pole hauling, external resources will be used.
- Gas Operations: For core work tasks, such as emergency response, customer service work, and routine operations and maintenance, internal resources will be used. All design jobs are offered to the gas supervisors for review and determination whether a company crew can perform or whether there is internal resource to perform work to meet the schedule. For replacement and emergent capital jobs over $100K, the projects are put out to bid to approved and qualified gas contractors.

The next table summarizes the 2010 Labor Cost Distribution.

[redacted]

The Hourly Cost of in-house and contractor resources are then compared to determine if there are any cost saving opportunities. This hourly rate is developed based on the crew rates (salary of a crew of 2 linemen plus the hourly charge of a bucket truck). For internal resource, the wage rate is developed by dividing the total O&M labor costs by the total O&M job-hours. The hourly vehicle rate is then added to arrive at the in-house hourly rate. The contractor hourly rate is developed from each of the eight biggest contracts. These eight contractor hourly rates are then weighted using the total contract values respectively for NYSEG and RG&E.

[redacted]

Assuming equally productive, there will be a saving of about [redacted] per hour for NYSEG and [redacted] per hour for RG&E to perform T&D work with in-house resources.

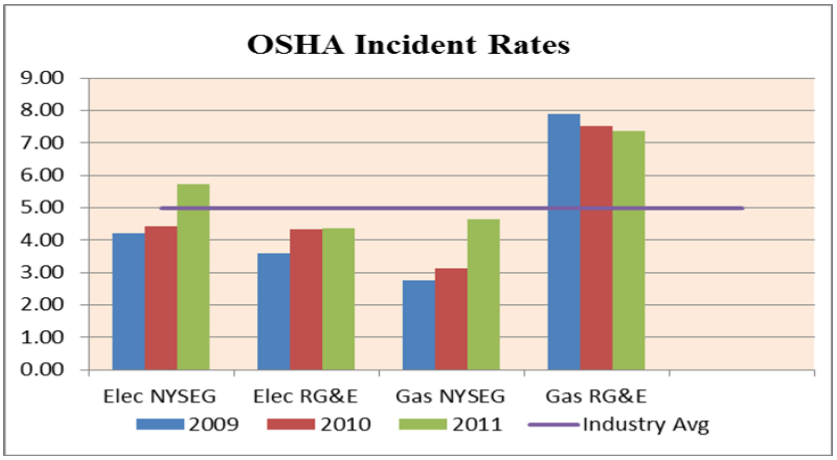
Presently the Company is operating to meet the requirements in Collective Bargaining Agreements. There are Contractor Field Operation Process Guide and Contractor Management and Oversight Reference Documents. These documents focus on how to manage the contracts, but not on how to balance the internal and contractor resources to maximize cost savings. Our recommendations in assigning physical work are:

- For Electric Operations, establish a corporate philosophy, policies and supporting guidelines to balance in-house and contractor resources which will greatly enhance cost savings opportunities on a continuous basis. The guidelines should include methods and historical factors to compare Total Company Labor Costs versus Total Contractor Costs (including a portion of the Company overhead and support costs, such as supervision and procurement allocation costs).
- For Gas Operations, unit pricing is used for minor capital work and it is appropriate to continue to do so. However, since capital work over $100,000 is competitively bid utilizing hourly rates, it is still advisable to establish a corporate philosophy, policies and supporting guidelines to balance in-house and contractor resources for major projects.

A major issue that surfaced from our work is how IUSA establishes a balanced and appropriate level of internal resources. The lack of internal resources appears to be a main driver for some work to be contracted. This issue should be examined along with all other resource management related recommendations.

5. **Conduct a root-cause analysis on the continuous high trend in OSHA injury rate in Gas Operations and implement a corrective action program.** *(Conclusion #27)*

For OSHA Incident Rate, Gas RG&E is unacceptably high on a continuous basis and this problem needs to be addressed. Also, all groups are trending higher also in 2010.



OSHA Incident Rate is defined as the number of OSHA recordable incidents/illnesses times 200,000 hours divided by the total hours worked. When the indicator is consistently at a high level, some investigations need to be conducted to identify the underlying causes on the types of injuries with high occurrences. Then the findings and lessons learned should be incorporated into future training sessions for all work groups.

If a root cause analysis has already been performed and communicated, and the message is not getting through, then further study is needed to identify whether there are new kinds of injury, the re-training is ineffective, or the workers' degree of safety consciousness is inadequate.

The Company should come up with a corrective action plan and closely monitor this indicator for future years to see if this work group brings the measurement to an acceptable level.

We do not anticipate any incremental costs from implementing this recommendation. Producing improved safety rates is the goal; *i.e.*, the benefit of implementation.

6. **Establish a structured corporate approach, policies and supporting guidelines to provide managers and supervisors with a framework to manage non-exempt employee overtime.** *(Conclusion #28)*

Overtime decisions are at the discretion of the managers and supervisors overseeing the work. There are no policies or guidelines on how to set the overtime target each year in different areas of work. There are also no metrics to monitor the overtime level and no requirements to perform analysis to determine the root causes when it is out of control (refer to Recommendation #7).

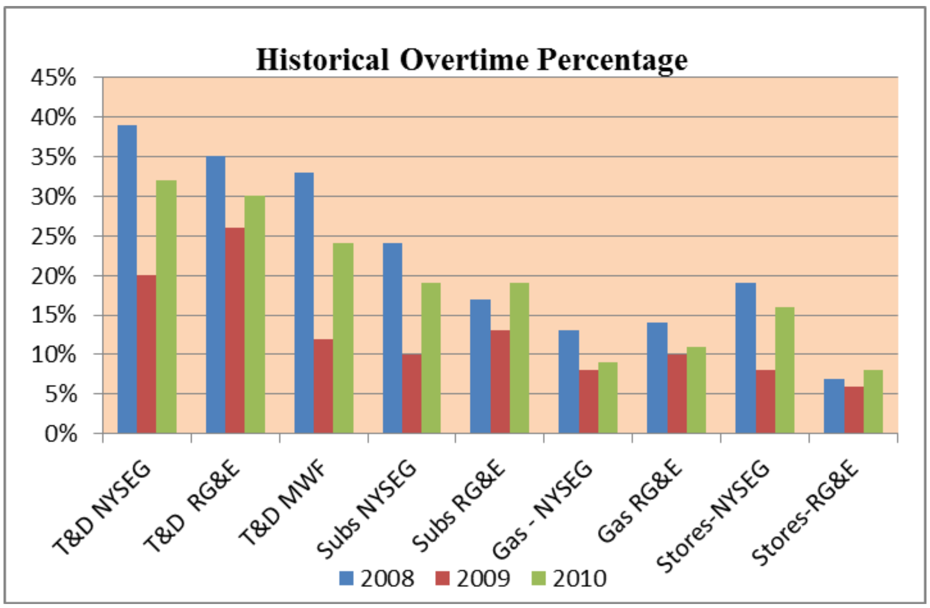
A clear policy, starting with a "the less the better" presumption is necessary. Targets should also be established for reasonable levels of overtime during the budgeting process, which will be driving future overtime to lower than the current level. Performance metrics should also be developed and reviewed at the appropriate level on a monthly basis.

A major issue that surfaces might be the proper internal resource level. Consistent high levels of overtime; *i.e.*, over 20 percent over a period of three years, indicates that the internal resource level is likely too low. This issue should be examined along with all other resource management related recommendations.

We do not anticipate substantial incremental implementation costs. Success in reducing overtime levels to rates more typical of close, effective management will produce very substantial savings.

7. **Prepare an analysis of overtime expenditures on Electric Operations and Stores, including root causes of the high trends and strategies for attaining a predetermined target.** *(Conclusion #28)*

There has been little analysis of overtime. The overtime level does not appear in any performance metrics that have been provided. There is also no documented review of overtime at any level. As the next chart demonstrates, some overtime levels are extremely high. T&D Overtime levels for both NYSEG and RG&E are consistently at an unacceptably high level for the past three years. In 2010, it is 32 percent for NYSEG (48 percent in Brewster, 51 percent in Mechanicville, and 42 percent in Liberty regions) and 30 percent for RG&E (39 percent in Canandaigua, 29 percent each in Sodus and Rochester). Substation overtime in 2010 is 19 percent for both NYSEG (Brewster 28 percent, Elmira 27 percent, Mechanicville 24 percent, Liberty 24 percent, Ithaca 23 percent and Lancaster 22 percent) and RG&E. Stores overtime level is doubling the previous year at 16 percent in NYSEG in 2010. Mobile Work Force doubles in 2010 to 24 percent. Another observation is that overtime for every group is trending towards the high level of 2008.



With the exception of Gas Operations, the overtime level for the other operations exceeds levels normally considered to be effective. We have not seen focused consideration by management of root causes or attempts at corrective measures. Other, related issues heighten concern about overtime levels:

- Is the work force sized appropriately, or does this excessive overtime suggest a lack of resources?
- Are the additional hours indicative of added quantities of work or productivity decline?
- What impacts do high levels of overtime have on costs and productivity?

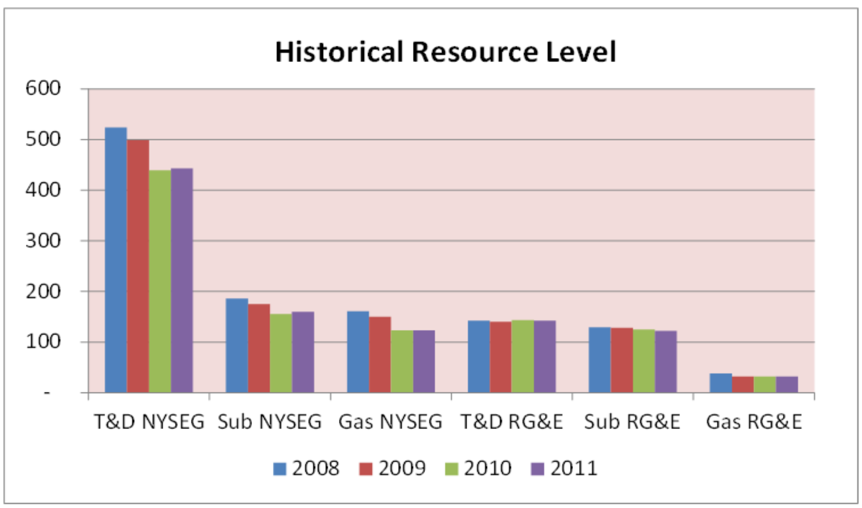
- What actions have been taken by management as this trend has continued? Were they aware and involved or is this now a surprise?

The optimum level of overtime in any organization is a function of many factors. In general, organizations should start with a simple philosophy "the less overtime the better." Overtime raises costs through premium time, reduces productivity, affects safety, and lowers work quality. We cannot say what the optimum level of overtime should be for IUSA, but we can reasonably conclude that it is well under 20 percent. Management should set an overtime target level, of say 15 percent (half of which could be earmarked for emergency responses), and require additional justifications for exceeding the target.

A major issue that surfaces here might be the proper internal resource level. This issue should be examined along with all other resource management related recommendations.

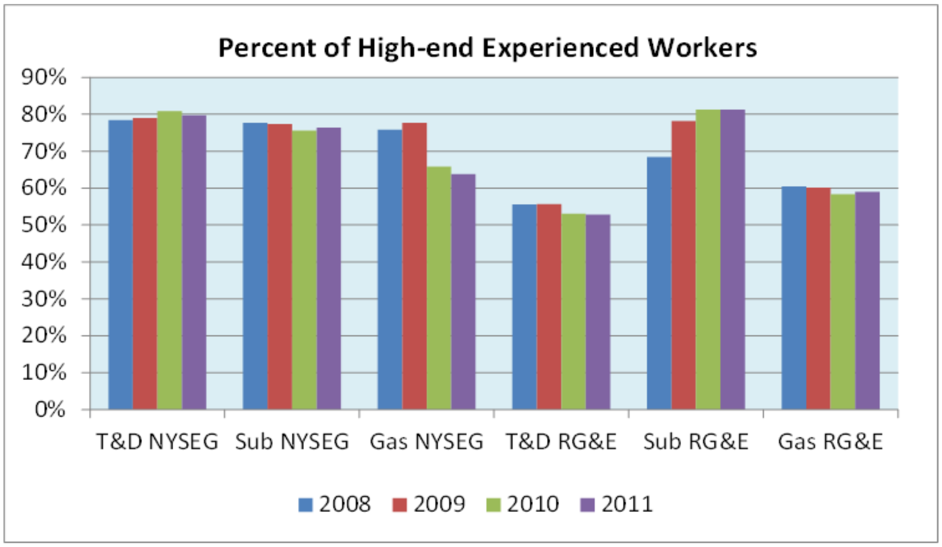
8. Develop the capability to continuously assess and monitor the productivity and cost impact of the expected retirement of linemen. *(Conclusions #21 and #26)*

IUSA has not closely analyzed how to address expected retirements of physical workers across the coming years. The next table shows historical work force levels.



The chart shows that all three types of work force in NYSEG have been decreasing for the past three years, while RG&E is holding steady. The 2011 data is as of the end of the first quarter; hopefully it shows the beginning of a reversal of a downward trend for NYSEG.

An examination (shown in the next chart) of the high-end skillful and experienced workers (with the title of chief, lead, senior, gang-foreperson or first-class), who are the potential retirees for the next five to ten years raises significant concerns on how to replace them in an appropriate manner.



In terms of replenishing the aging work force, the level of apprentices is summarized on the table below.

Apprentice	2008	2009	2010	2011
T&D NYSEG	74	2	1	7
Sub NYSEG	15			
Gas NYSEG	16		23	23
T&D RG&E				
Sub RG&E				
Gas RG&E				

It takes at least three and a half years of training before an apprentice can become qualified in Electric Operations and Gas Operations. It takes about six to seven years before the workers are fully qualified to work on their own. It would take ten to twelve years for them to rise to a lead or senior position. The Company recognizes the need to replenish the aging work force, and is counting on the new IUSA Line Worker Workforce Model to analyze its requirements.

IUSA contends that the Company does have the capability to analyze and replenish the retired work force, albeit not in the most sophisticated way. The Company just developed and placed in operation the new IUSA Line Worker Workforce Model to plan its Electric Operations resources. The Company needs to act with a greater sense of urgency in replenishing the aging work force. It starts by realizing how the productivity and work quality are affected by the loss of skilled and experienced workers in the very near future. Both of these will have substantial cost implications, if not addressed in a timely and adequate manner. Liberty therefore recommends a cost study to be performed with the objective to develop the capability on a continuous basis to evaluate the productivity and cost impact resulting from a high rate of retirements.

The Company currently does not measure productivity. Initially it will be very difficult to have good visibility, but after there is a solid history of productivity measurement, more accurate assessment can be attained. With the implementation of the holistic cost management program, IUSA will be more equipped (by producing insightful productivity analysis, a valid control base, and solid cost projections, for example) to maintain this evaluating capability.

We estimate that it will cost about $100K [redacted] to conduct the study. [redacted] it will take only an insignificantly small change in how future requirements are met to justify the expenditure.

9. Include in future contracts a requirement that contractors performing physical work report expended job-hours and quantities installed or completed (at a property unit level). *(Conclusion #33)*

IUSA now manages contractors by production only. Productivity is not a consideration as long as the projects or tasks get completed. At the completion of each contract, the supervisor will fill out a Contractor Performance Scorecard that focuses on four main areas. The outcomes of the rating on the above criteria are (a) satisfactory or (b) unsatisfactory only.

Performance metrics should be established to monitor the contractor’s performance. With these two added pieces of information (unit cost and unit job-hour rate), the performance of a contractor can be analyzed more robustly. Quite often, contractor’s performance will improve when it knows it is being monitored. The data will provide valuable information for monitoring monthly progress and analyzing performance to anticipate problems. The information is useful also when it comes to evaluate the bidding of similar contracts in the future. For that work that the in-house resources have the skill to perform, productivity will become another factor in the evaluation of whether to contract the work.

In the new holistic cost management environment, productivity will be measured and monitored closely. The Company should not hold its contractors to a lower standard than its own work force.

We do not anticipate that implementing this recommendation will entail significant costs. Implementation benefits will come in the form of improved information about performance drivers, productivity information details, improved productivity and quality in contractor work, and enhanced ability to compare the cost and effectiveness of resource types.

10. Evaluate the most cost-effective size of the overall internal work force, including the Mobile Work Force, taking into account such factors as future planned workload, worker versus contractor efficiency and productivity, and work rules; strive to achieve a balanced and cost-effective workforce level. *(Conclusion #32)*

Presently the Mobile Work Force (MWF) in NYSEG has 32 linemen performing Electric Operations work. In 2010, they produced $2.3 million in capital work and an additional $1.0 million in O&M work. Liberty performed an analysis was performed on the overall 2010 workload to examine if there are any cost savings opportunities. The purpose was to demonstrate the approach and methods to assess the magnitude of work that can be assumed by the internal work force. The next table summarizes the 2010 labor cost distribution.

2010 Actual Labor Cost Summary (All Costs in Million)				
Resource Type	**Capital**	**O&M**	**Total**	**Percent**
Internal	16.6	37.1	53.7	54%
Non-Specialty Contractors	41.7	4.3	46.0	46%
Total	58.3	41.4	99.7	100%

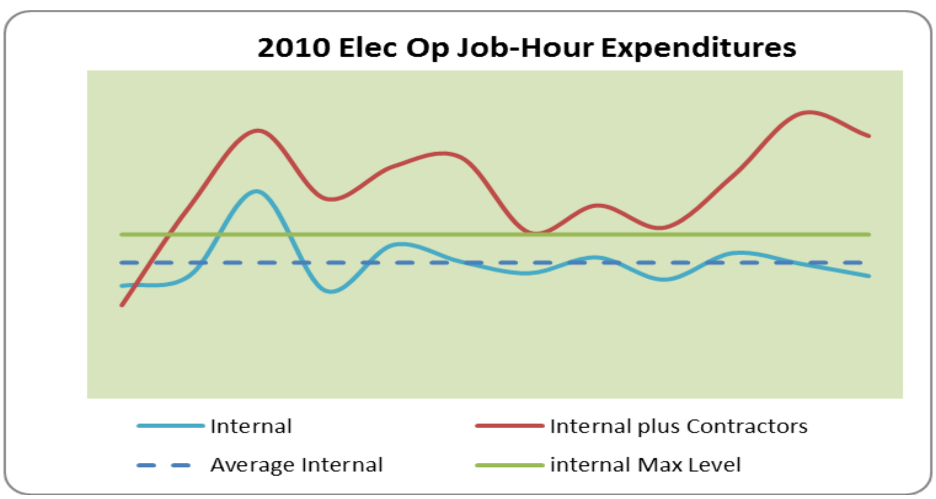
The goal of this analysis was to determine if the MWF can perform work at a lower cost than contractors. If so, then it would seek to identify the appropriate amount of workload that can be assumed by MWF, the additional internal linemen required, and the magnitude of potential cost savings.

The workload was analyzed in terms of expended job-hours in the thirteen NYSEG regions, excluding MWF. The total workload includes Capital and O&M work for both internal and external (contractor) resources.

The development of workload as based on the following:

- Actual Capital job-hour information for internal resources provided is inconsistent with Capital labor costs. Average O&M wage rate has to be used to estimate the actual Capital job-hours.
- Actual Contractor job-hours are not tracked. Hence, it had to be estimated using an average contractor hourly rate. This hourly rate was developed based on the crew rates (salary of a crew of 2 linemen plus the hourly charge of a bucket truck) from each of the nine biggest contracts. These nine contractor hourly rates are then weighted using the total contract values. [redacted].

The following chart depicts the workload distribution for NYSEG.



In converting contractor costs to contractor hours, January has to be discounted for two reasons: (a) billing lag; and (b) a negative value of $1.4 M in the Ithaca region, probably due to accrual reversal from the previous year. Major storms caused sharp rises of internal resource charges in March and to a lesser extent in May. The "average internal" resource level for the sum of all 13 regions is about 66K job-hours. The "Internal Maximum Level" could have been 80K job-hours, had there been available internal resources. Therefore, about 14K job-hours per month or 165K job-hours per year could be performed by MWF, if its average hourly rate is cheaper. These numbers would produce an increase of about 90 linemen, using 1,800 job hours per person per year.

The calculated average "contractor hourly rate" [redacted]. This rate is in line with the estimated contractor hourly rate [redacted] as used in Workforce Planning Model. The calculated average contractor hourly rate should be lower, because it is developed from total actual contract costs, which include some low end or lower cost contractor work. The next table shows the calculation of the average "internal hourly rate."

[redacted]

The difference in hourly rate [redacted] We then calculated net costs savings as follows:

- The total cost difference [redacted] = $4.4 M
- Cost per Hire [redacted] = $0.9 M
- Training Costs - 736 training hours spreading over 3.5 years at [redacted] = $885K for the first three years and $442K for the 4th year
- Traveling Compensation [redacted] = $810K/year.

Calculation of Net Cost Savings (All costs in million)					
Description	1st Year	2nd Year	3rd Year	4th Year	5th Year
Annual Cost Difference	4.43	4.43	4.43	4.43	4.43
Hiring Costs	0.90				
Training Costs	0.88	0.88	0.88	0.44	
Traveling Compensation	0.81	0.81	0.81	0.81	0.81
Net Cost Savings	**1.84**	**2.74**	**2.74**	**3.18**	**3.62**

This analysis demonstrates the potential for substantial cost savings from using MWF as an internal contractor to perform steady excessive work above the routine regional workload in the thirteen regions. This analysis used 2010 workload; IUSA should, of course, determine the appropriate size of the MWF work force using a forecast of future workloads. We acknowledge that there are obstacles that need to be addressed, such as the existing labor agreement on the limit of MWF resource level. There are some prerequisite requirements such as effective resource scheduling and close monitoring of the MWF wage rates. There is also the issue of accepting the fact that the initial productivity might not be as good as that of the contractors. However, in the longer term, not only will the Company actualize true cost savings because of lower wage rates and better work quality because of facility familiarity and ownership, the additional benefits to implement this recommendation will be the establishment of a consistent and transparent approach when to use contractors and offer a path to replenish the aging work force with new recruits to the Electric Operations organization.

11. Promote the ability of NYSEG and RG&E workforces to perform cost-effective work in each other's territories. *(Conclusion #25)*

Work forces from NYSEG and RG&E seldom cross boundaries to perform work in each other's territories. An examination of the 2010 time charges on both Companies confirms this fact. There are great opportunities for cost savings if the work forces start to work in each other's areas, when both Companies reach an optimal resource level. The next table summarizes the 2010 Labor Cost Distribution.

[redacted]

In 2010, about 45 percent of the work on average is contracted both in electric and gas operations. There are variations in reasons between NYSEG and RG&E, electric and gas operations, and capital and O&M. However, there are cost savings opportunities to the extent that the labor cost of in-house resource is lower than that of contractors.

We compared the Electrical Operations Hourly Cost of in-house and contractor resources. We developed hourly rates based on the crew rates (salary of a crew of 2 linemen plus the hourly charge of a bucket truck). For internal resource, the wage rate was developed by dividing the total O&M labor costs by the total O&M job-hours. The hourly vehicle rate was then added to arrive at the in-house hourly rate. The contractor hourly rate was developed from each of eight biggest contracts. These eight contractor hourly rates were then weighted using the total contract values respectively for NYSEG and RG&E.

[redacted]

Assuming equal productivity, there could be a savings of about [redacted] per hour for NYSEG and [redacted] per hour for RG&E by performing T&D work with in-house resources.

The labor costs for gas work cannot be similarly compared at this time because the gas contractor rates are unavailable for contracts over $100K (projects under $100K are contracted via unit pricing). However, the concept is the same. As long as the labor cost is lower for in-house resources, there are cost savings opportunities.

It might take some time for IUSA to determine the optimal internal resource level. The benefits go beyond just cost savings when work forces of both Companies start to work in each other's areas on a cooperative and continuous basis. It is always advantageous to have in-house resources working, for system familiarity and work ownership purposes. Over the longer term, it will help to build a more vibrant, younger work force to replenish the expected upcoming attrition through retirements. Otherwise, IUSA faces the risk of finding itself increasingly "hostage" to contractors.

This issue should be examined along with all other resource management related recommendations. For example, the most prevalent concern we have heard from unions, apart from safety, is that too much work is being contracted. There is a separate recommendation to advise upper management to publish a policy or guidelines for transparency purpose on how to balance in-house resources and contractors such that misunderstandings can be minimized.

D. Performance Measurement

1. Background

The performance of an organization is a function of a complex interrelationship between several criteria, such as effectiveness, efficiency, quality, productivity, quality of work life, innovation, and profitability. Our evaluation focuses on two: productivity and quality. Productivity is a relationship between input (job-hours or labor costs) and output (work accomplished or service delivered). Quality is doing it right the first time. If the quality is poor, that means the work is not done right.

Measurement is an important management function. One cannot manage what one does not monitor, and one cannot monitor what one does not measure. The objective of measurement is not just to know how well you produce, but more importantly to pinpoint problems for corrective actions or to identify areas for improvement. In this section, we will evaluate the continuous improvement culture of the Company, the quality control program, how the Company collects quantities of physical work, and how productivity is being measured.

The criteria by which Liberty evaluated performance measurement included the following:

- A culture of continuous improvement should be in place that encourages management and employees to enhance work processes.
- An effective program of quality control should be in place that blends with the work flow and avoids checkpoints or delays that unnecessarily disrupt the work while also capturing defects early enough to minimize the need for extensive rework.
- Physical quantities (for example, number of feet of gas main removed, number of poles installed, feet of distribution line upgraded, number of transformers replaced) or work performed (number of trouble calls, number of services installed, number of pole

inspections, number of gas leak surveys, for example) should be collected consistent with the WBS and directly linked to their associated costs incurred.

- Productivity should be measured wherever practical and meaningful and compared to credible standards. Such measures should be on both a macro (collective) basis and micro (detailed tasks) basis. Definitive productivity standards should be catalogued for all standard work activities and specialized productivity standards designed for unique substantive tasks.

2. Findings

a. Continuous Improvement Programs

Prior to 2010, IUSA had only minor success in continuous improvement efforts. Since forming the Business Transformation Department to align employees, processes, and technology with the Company's business strategies and vision, a formal continuous improvement program, known as Rapid Results, was launched in the beginning of 2010. It is a structured, results-focused approach to implement improvement initiatives with strategic priorities.

The key to the success of this concept is to focus on projects designed to achieve measurable progress in 75 to 100 days. Every few months, identified opportunities of improvement are launched continuously as a group and distinguished as waves. Not all initiatives result in cost savings. For those that have an obvious cost benefit, attempts are made to estimate the potential cost savings. For those that do, the total aggregated estimated cost savings for Electric and Gas Operations initiatives are $1.4 M for Wave 1, $6.4 M for Wave 2 and $4.7 M for Wave 3. There is a step in the Rapid Results process to validate the cost savings by the Control and Administration Department. The auditing results of Wave 1 and Wave 2 are completed. Because the current accounting code structure does not focus on productivity, the extent of the cost benefits of these initiatives could not be isolated for validation.

The Company is currently implementing Wave 4 (14 projects) and Wave 5 (13 projects in 2011). As the projects are completed, audits will also be performed to document realized cost savings.

IUSA has another Continuous Improvement Program, which it calls the Workout Methodology. This program is intended as a fast-paced technique used to develop grass-roots solutions to defined problems, and to eliminate barriers to immediate action. Three workout solutions have been completed since inception, but the cost savings will not be validated until next year.

A third continuous improvement program, known as Best Practice Idea Implementation Process is designed to allow any employees to submit best practice ideas in their business areas. The Business Transformation Group will evaluate the merit with their business area executive. If the idea is selected for implementation by the business area, the project scope, responsibility, cost/benefit, scheduling and reporting will be defined. The Business Transformation Group has responsibility for maintaining a log of submitted ideas. Some significant best practice ideas may become a Rapid Result project in the subsequent wave. Over 600 ideas were submitted in 2011, of which 51 were implemented locally, while three major ones were implemented under Wave 3 and 4 of the Rapid Results Process.

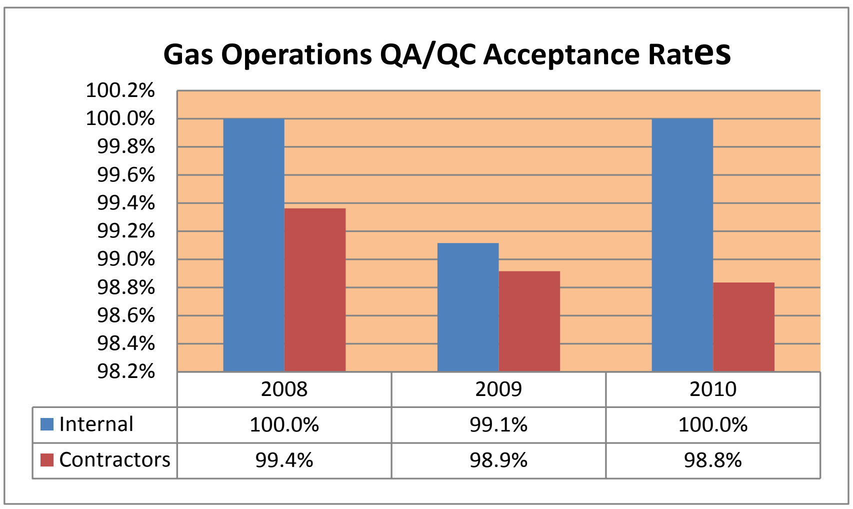
b. Quality Assurance Program

Quality Assurance (QA) comprises the systematic monitoring and evaluation of the various aspects of a project, service or facility to maximize the probability that standards of quality are being attained by the production process. Quality Control (QC) is the observation techniques and activities used to fulfill requirements for quality. The end-product should be “fit for purpose” (suitable for the intended purpose) and “right the first time” (mistakes minimized or eliminated). QA/QC covers assurance and inspection of the quality of received materials, installed components, and services related to production. The QA/QC program envelops all work performed by internal work force and contractors.

The Gas Quality Assurance/Quality Control Manual contains the various procedures and processes associated with auditing, material assurances, field inspections, corrective action and reports. The Electric QA/QC Control Manual is currently under development.

i. Quality Acceptance Rates

Gas Operations’ formal QA program performs field and record audits based on the Public Service Commission Code and O&M Procedures Manual. Corrective Action Reports (CAR) or Non-Conformance Reports (NCR) will be issued for areas of concern or violation.



Nineteen NCRs for contractors were issued in 2008, 24 in 2009, and 28 in 2010. The acceptance rates for contractors were good for the past three years; all exceeded 98 percent. The situation has been different for the Company work force. The acceptance rates all looked very good, but the data were misleading. Contractor’s inspections averaged 2,500 per year for the last three years. For IUSA internal work there were only 73 total inspections in 2008, 113 in 2009 and a meager 7 in 2010. This is a very strong indication that the Gas Operations QA/QC organization is severely understaffed.

Electric Operations does not collect QA acceptance data, because there is currently no formal QA/QC Program. The field supervisors essentially assume the QA/QC roles. By closing out the work orders, the supervisors basically confirm the work is completed satisfactorily.

ii. QA/QC Inspector's Qualifications

For Gas Operations, the QA inspector holds the title of Lead Analyst – Gas Engineering. The basic requirements are at least six years of related field experience and three years of directly related technical experience in gas construction, operations and maintenance or an associate degree. Quality Control inspectors ensure the field installations meet all specifications. They ensure all facilities are installed safely, reliably and economically. The inspectors function also as a critical liaison between customers, field operations personnel, and contractor personnel, and state government agencies. They are required to have basic knowledge of gas design and specifications. They have extensive and diverse utility field experiences. They need to be Gas Safety and Operating Rules (GSOR) certified.

For Electric Operations, the construction supervisors assuming the QC inspector role have many years in related training and field experience in electrical design, construction and contracting.

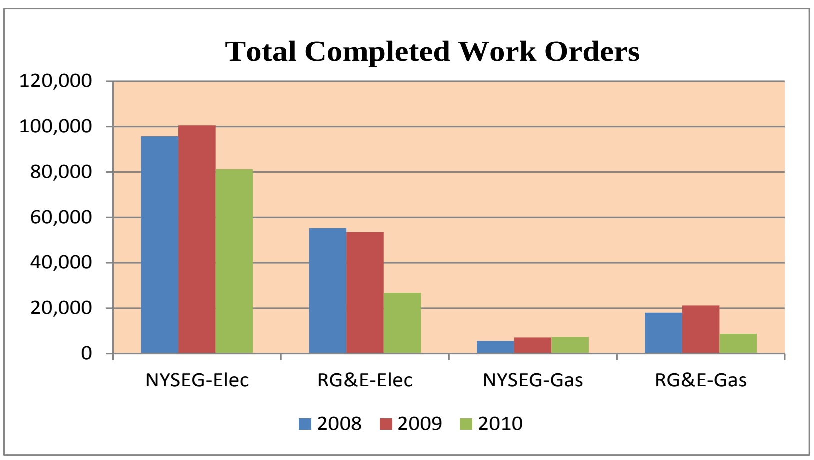
iii. QA/QC Inspection Headcounts

The Gas Operations Quality Assurance staffing for the past three years is low: 5 in 2008, 5 in 2009, 3 in the first half of 2010 and down to 2 after July 2010. For Quality Control, there are 15 inspectors at NYSEG and 7 field inspectors at RG&E.

For the period of 2008 to 2010, no formal Quality Assurance Group existed in Electric Operations. Field inspections were typically performed by the Line and Substation organizations. For in-house electric construction crews, regular field supervisors are responsible for quality assurance. For contracted electric construction crews, IUSA utilized about 20 contingent based workers (retired line supervisors) to provide contractor oversight and quality assurance.

c. Physical Quantity Collection

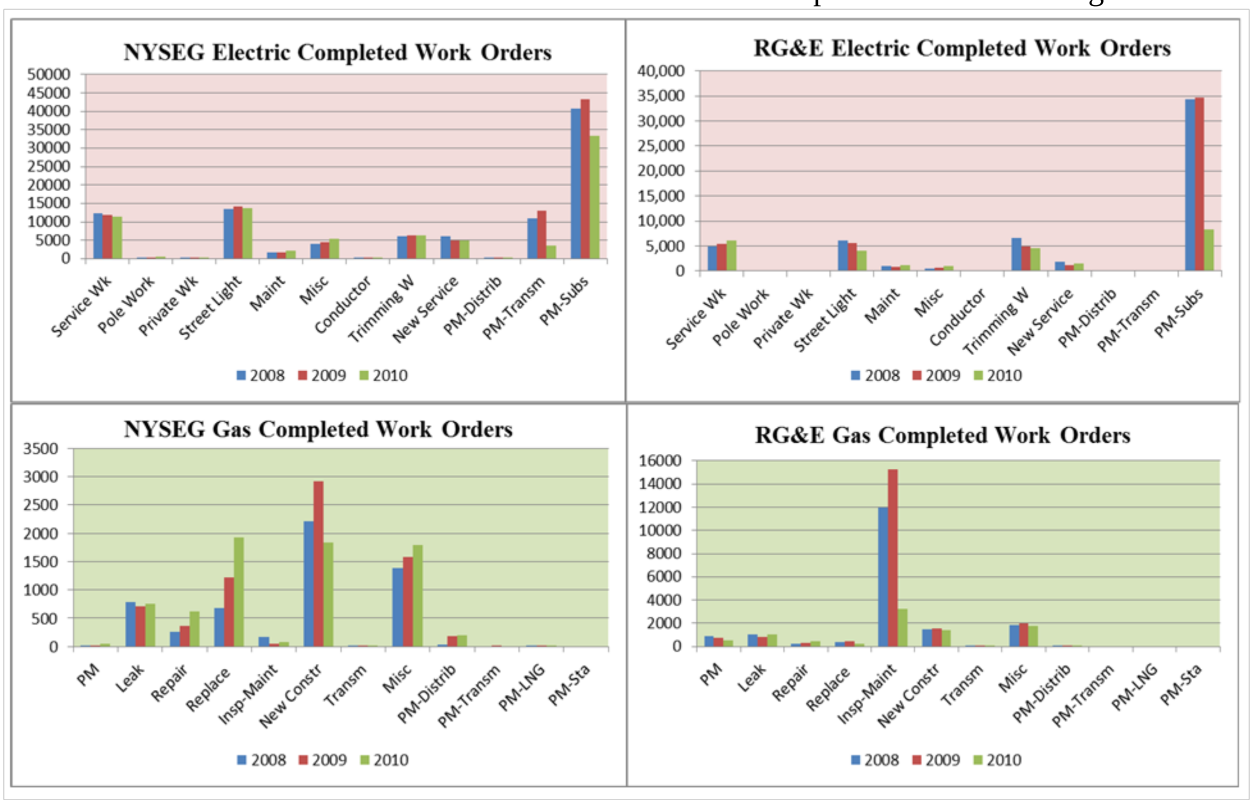
IUSA manages the physical work by work production. The SAP is set up to monitor work completion by work orders. Liberty does not regard the work order as the appropriate quantity measurement for effective work management. This can be illustrated by the following chart.



In terms of historical annual total work orders completed (acknowledging that not all work orders were created equal among different types of work):

- For Electric Operations, both RG&E (down 50 percent) and NYSEG (down 20 percent) dropped significantly in 2010.
- For Gas Operations, RG&E was down 60 percent, while NYSEG was at about the same level.
- From the work order standpoint, it appears that less work was being accomplished in 2010.

Examinations of the detailed work orders showed the results depicted in the following charts.



For Electric Operations, NYSEG was down 20 percent in 2010 due to completing less work in Transmission preventive maintenance and Substation preventive maintenance work. For Electric Operations, RG&E was down 50 percent in 2010 due to completing less work in Substation preventive maintenance, street lighting and Tree Trimming. For Gas Operations, RG&E was down 60 percent in 2010 due to completing less work in inspection/maintenance.

There were certainly some underlying reasons behind the lower production. None of these three issues was addressed in any of the management reports at any level. For more effective work management, IUSA should monitor productivity instead of production. The physical quantities need to be collected and directly linked to the associated installation job-hours or installation costs.

The next table summarizes the current, 64 electrical activity codes and 29 gas activity codes created to collect costs.

Operations	Group	No. of Activities
Electric	Conductor Overhead-Underground	10
	Maintenance Work	7
	Miscellaneous	2
	New Service Units	5
	Pole Work Units	8
	Private Work	2
	Service Work Units	15
	Street Light Work	10
	Trimming Work	5
	Total	64

Operations	Group	No. of Activities
Gas	Inspection/Maintenance	7
	Leak	1
	Miscellaneous	6
	New Construction	5
	Preventive Maintenance	1
	Repair	2
	Replace Construction	6
	Transmission	1
	Total	29

Most of the quantity information is actually available at the work order level. For example, some activities, such as gas leak, pole replacement, new service, and gas repair, are isolated on a per unit basis in each work order. For other activities, such as street lights, pole inspection, and valve inspection, the multiple quantity information is available within the work order. The Company could make good use of the quantity information along with the job-hours and costs captured at the work order level to monitor and analyze productivity.

d. Productivity Measurement

i. Performance Indicators

IUSA uses performance indicators at different levels:

- Weekly Measurement Report by Operational Manager – safety, reliability, financial, and the following indicators to be developed later: productivity, wrench time, continuous improvement, and customer satisfaction.
- Electric Operations NYSEG/RG&E Consolidated Group Incentive Plan Targets – O&M funding trigger, O&M expenses, achieve capital spending to budget, safety & reliability indices, replacement of leak prone mains and services, responses to gas odor calls, damage prevention, PSC complaint rates, Stray Voltage program, implementing major projects, fleet availability, achieving business transformation milestones.
- Gas Operations Measurement Report by Region – Emergency response, gas leak survey & repair, damage prevention, gas meter exchanges, vent/regulator inspection program,

achieving mandated standards, achieving gas regulatory, safety & reliability targets, achieving combined corporate safety index

- NYSEG Gas Operations Team NY Performance Measures – Natural gas leak response in less than 30, 45, and 60 minutes, mandated leak repair, rate of total damages per 1,000 gas related mark-out tickets, mandated pipe replacement
- RG&E TeamNY Performance Measures – Customer Services, CAIDI, new service installation SAIFI, capital spend target, vegetation management, total inventory turns, availability of fleet, gas leak response, leak management, leak prone pipe replacement.
- Business Area Objectives – Net income, non-fuel O&M, sales (units), sales (revenues), contribution margin
- Performance Management Report – Combined Safety Index, CAIDI, New Service Installation, Emergency Service Restoration Plan, Gas Leak Responses, Lead Prone Pipe Replacement, Leak Management, Prevention of /Excavation Damages, SAIDI, Vegetation Management, Customer Satisfaction, Meter Read, Average Speed of Answer Customer Complaints, Uncollectibles.
- Labor Movement Report – Measuring percent of labor shifted from O&M to Capital

None of these reports provides productivity measurements. None of the business units has productivity as a pay-for-performance goal. The predominant cost measurement is dollar performance against budget.

A sample of the monthly Performance Management Report follows.

Apr-11		Central Maine Power (CMP)						NYSEG						RG&E					
		Results						Results						Results					
Metric	Description	Target	Month	YTD Actual	YTD Target	Status	Max. Penalty^	Target	Month	YTD Actual	YTD Target	Status	Max. Penalty*	Target	Month	YTD Actual	YTD Target	Status	Max. Penalty*
Customer Service																			
Customer Satisfaction	Satisfaction Survey Results - Top 5 in Northeast	Top 5	Top 5	Top 5	Top 5	●		Top 5	1	1	Top 5	●		Top 5	2	2	Top 5	●	
	Contact Satisfaction	≥85%	87.0%	91.0%	≥85%	●	^	≥73%	N/A	N/A	≥73%	N/A		≥85%	91.2%	90.8%	≥85%	●	^
Average Speed of Answer	Calls answered within 30 seconds.	≥80%	85.8%	86.6%	≥80%	●		≥63%	68.0%	72.0%	≥70%	●		≥77%	85.0%	81.4%	≥77%	●	^
Customer Complaints	# complaints/1,000 customers.	≤1.2	0.13	0.13	≤1.2	●	^	≤1.0	0.2	0.1	<1.0	●		≤1.8	0.3	0.3	≤1.8	●	
Meter Read	Meter Read Access Rate	≥94%	97.5%	90.5%	≥94%	●	^	N/A	N/A	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	
	Estimated Meter Reads	N/A	N/A	N/A	N/A	N/A		≤6.1	3.3%	6.07%	≤6.1%	●		≤6.0	2.4%	3.0%	≤6.0	●	^
Uncollectibles	Customer Service Bad Debt Write-Off (million$)	$4.7	-$0.29	$1.3	$4.7	●		$15.1	$1.4	5.4	≤3.3	●	^	$15.2	$0.9	$4.0	$4.0	●	^
	Debtor Days as of December 2011	44	43.6	43.6	35.9	●	^	41	51.4	47.1	42	●	^	54	60.9	55.3	55	●	^
Electric T & D																			
Customer Average Interruption Duration Index	CAIDI	≤2.18	1.97	1.97	≤2.18	●	^	≤2.08	2.20	2.20	≤2.08	●	^	≤1.90	1.59	1.59	≤1.90	●	^
New Service Installation	By date promised	>85%	98.15%	98.15%	>85%	●	^	N/A	4.2	4.7	N/A	●		N/A	5.9	5.5	N/A	●	^
Emergency Service Restoration Plan (Annual Drill)	Test Schedule and Date Complete	Annual	N/A	To Be Scheduled	Annual	●		Annual	4Q2011	on target	on target	●		Annual	4Q2011	N/A	4Q2011	●	
NERC Standards Certification (Annual)	Test Schedule and Date Complete	Annual	N/A	58	58	●		Annual	Ongoing	20	30	●		Annual	Ongoing	Ongoing	Ongoing	●	
Black Start Plan (Annual Drill)	Test Schedule and Date Complete	Annual	N/A	0 of 6	October	●		Annual	27-Apr	27-Apr	27-Apr	●		Annual	27-Apr	27-Apr	27-Apr	●	
Annual Load Relief Drill	Test Schedule and Date Complete	Annual	N/A	N/A	June	●		Annual	N/A	N/A	8-Jun	●		Annual	N/A	N/A	8-Jun	●	
Maine Operating Procedure #11 (Annual Drill)	Test Schedule and Date Complete	Annual	N/A	6 of 6	6	N/A		N/A	N/A	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	
Gas Distribution																			
Gas Leak Responseness	Less than 30 min.	N/A						≥75%	84.38%	84.38%	75%	●	^	≥75%	90.15%	90.15%	75.00%	●	^
	Less than 45 min.	N/A						≥90%	90.15%	90.15%	90%	●		≥90%	98.76%	98.76%	90.00%	●	^
	Less than 60 min.	N/A						≥95%	97.11%	97.11%	95%	●		≥95%	98.76%	98.76%	95.00%	●	
Lead Prone Pipe Replacement	Mains (Miles) (Annually)	N/A						≥24	0.20	0.20	0.8	●	^	≥24	4.69	4.69	3.7	●	^
	Services (Annually)	N/A						≥1,200	255	255	228	●	^	≥1,000	444	444	490	●	^
Leak Management	Year End Backlogs	N/A						<100	66	66	100	●	^	<200	216	216	200	●	^
Prevention of Excavation Damages	Overall (per 1,000)	N/A						≤2.00	0.77	0.77	2.00	●	^	≤2.00	1.33	1.33	2.00	●	^
	Mismark (per 1,000)	N/A						≤0.50	0.31	0.31	0.50	●	^	≤0.50	0.28	0.28	0.50	●	^
	Company & Crew (per 1,000)	N/A						≤0.20	0.00	0.00	0.20	●		≤0.20	0.21	0.21	0.20	●	
Engineering & Asset Management																			
System Average Interruption Frequency Index	SAIFI	≤2.00	0.49	0.49	0.57	●	^	≤1.20	0.32	0.32	0.31	●	^	≤0.9	0.26	0.26	0.016	Off Target	^
NERC/NPCC/ISO Compliance (Annual)	Support Compliance	Ongoing	Ongoing	Ongoing	Ongoing	●		Ongoing	Ongoing	Ongoing	Ongoing	●		Ongoing	Ongoing	Ongoing	Ongoing	●	
Vegetation Management	Trim Targets (Spans)	117,899	34,199	45,498	39300	●	^	N/A	N/A	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	
Information Technologies																			
Client Satisfaction	Client satisfaction survey results	≥7.5	N/A	N/A	≥7.5	N/A		≥7.5	N/A	N/A	≥7.5	N/A		≥7.5	N/A	N/A	≥7.5	N/A	
Service Desk Time to Answer	Answered within 30 seconds	≥85%	94.35%	85.95%	≥85%	●	^	≥85%	94.35%	85.95%	≥85%	●	^	≥85%	94.35%	85.95%	≥85%	●	^
Service Desk Resolution Rate	Percentage of calls resolved by level 1	≥70%	73.28%	71.57%	≥70%	●	^	≥70%	73.28%	71.57%	≥70%	●	^	≥70%	73.28%	71.57%	≥70%	●	^
Critical Systems Availability	% Availability for critical systems	≥99.75%	97.91%	99.46%	≥99.75%	●		≥99.75%	100.00%	99.93%	≥99.75%	●	^	≥99.75%	100.00%	99.93%	≥99.75%	●	^
SAP Response Time	Average on-line SAP response time (ms)	≤200	117.38	118.96	≤200	●		≤200	117.38	118.96	≤200	●		≤200	117.38	118.96	≤200	●	
Nightly Processing	Accurate & timely completion of nightly batch jobs	≥98%	100.00%	100.00%	≥98%	●		≥98%	100.00%	100.00%	≥98%	●		≥98%	100.00%	100.00%	≥98%	●	
Print Services	Same day customer bill production and mailing	≥99%	100.00%	100.00%	≥99%	●		≥99%	100.00%	98.75%	≥99%	●		≥99%	100.00%	100.00%	≥99%	●	
Disaster Recovery & Emergency Planning	One Successful Test per Data Center per Year	Annual	N/A	N/A	Annual	N/A		Annual	N/A	N/A	Annual	N/A		Annual	N/A	N/A	Annual	N/A	
Safety Measures																			
Combined Safety Index (CSI)	Employee Safety Measure	≥5.00	4.60	4.60	N/A	●	^	≤5.00	6.00	6.00	N/A	●	^	≤5.00	3.40	3.40	≤5.00	●	^

Note: * - The NY numbers include only direct penalties. Missing gas safety, electric reliability or customer service targets would also lower the NY companies ROE thresholds for determining customer sharing. The maximum impact of this in 2011 is $8.1M.
Note: ^ - There is a formula that determines the penalty associated with each CMP metric, however, the total penalty cannot exceed $5m.
Total Max penalty for NY $47.1M

Comments: NYSEG is below target for leak prone pipe replacement with less than 1% of the 24 mile target actualized (RGE has completed about 20% of their 24 mile target). RGE is slightly behind target in Gas Prone Service Replacement. NYSEG was behind on this target but completed 188 services in the past month, bringing them inline with monthly targets. The penalty for leak prone main and services is 300,000/per company and metric. RGE exceeded the Gas Backlog target in April. An increase in this metric is common during the spring and summer months. The penalty for RGE is 400,000. The metrics for Prevention of Damages was still slightly behind for RGE with a penalty of 130,000.

As mentioned above, the flagship PMP report displays metrics on safety, customer services, reliability, gas performance, electric performance, but none on cost and productivity.

ii. Productivity Measures

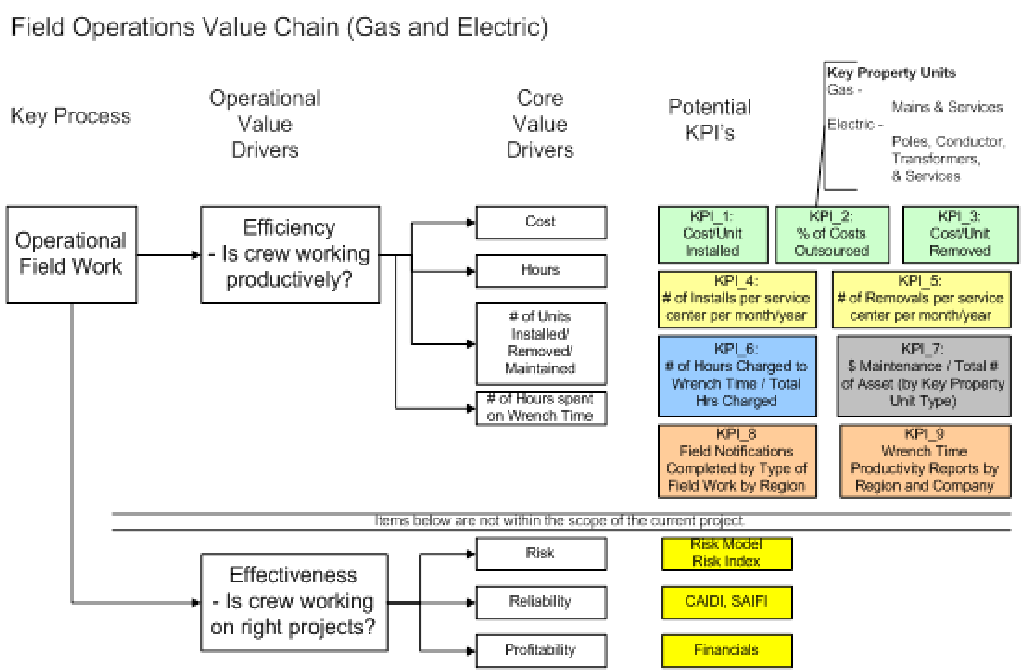
Electric and Gas Operations measure performance in the areas of safety, reliability, customer services, regulatory compliance, operations and maintenance, and budget adherence. Productivity is not specifically measured, as key commodity quantities are not established and monitored. Without measurement, it is difficult to affirm if there is any productivity improvement.

The Company recognizes this weakness. In early 2010, a cross functional team of IUSA employees was assembled to develop Electric and Gas Distribution Field productivity measures for proposed implementation at IUSA based upon data available in current systems. The goal of the team was to identify meaningful metrics that would provide relevant unit cost and crew productivity measures to Distribution Operations management. The metrics were to include both Company labor and external services (contractor field crews).

Based upon the concept of the Electric and Gas Value Chain, core value drivers were considered (cost, hours, no. of units installed/removed/maintained, no. of wrench time hours). Nine Key Performance Indicators (KPIs) were derived from these key value drivers. They were derived in two general categories:

1) Key Property Units KPIs – Cost per unit for Electric and Gas Distribution Capital Construction charged to SAP Distribution Compatible Unit Orders.
2) Maintenance KPIs - Dollars charged to SAP Internal Maintenance Orders.

A pictorial of the Distribution Field Operations Gas and Electric Value Chain follows.



The projected benefits of the KPI categories were then determined:

1) Key Property Units KPI benefits:
   - Ability to internally benchmark per unit costs for major service centers within an operating company
   - Ability to internally benchmark per unit costs between operating companies
   - Drive consistent data tracking and business processes within IUSA
   - Provide understanding of installed/removed/retired unit costs and cost drivers
   - Insight into capital asset investment by service center and operating company
   - Understand costs reported as internal labor versus external services
   - Provide insight into most cost efficient approach to construction work
   - Provide baseline for measuring increases/decreases in efficiency.
2) Maintenance KPI benefits:
   - Ability to internally benchmark maintenance costs and productivity for major service centers within an operating company
   - Ability to internally benchmark maintenance costs and productivity between operating companies
   - Provide baseline for measuring increases/decreases in efficiency
   - Assist in determining resource requirements
   - Insight into activity level for distribution system maintenance planning
   - Drive consistent data tracking and business processes within IUSA
   - Assist in determining resource requirements.

The period from July 2010 to December 2010 was used for Business Requirements Definition, specifications development and approval, internal resource estimation, KPI report development, data extraction programming and execution, data validation, and user report testing. The initial KPI reports were made available to Operating Management though both SAP R3 and Business Warehouse reporting and on the Company intranet portal in early December 2010.

Although these reports are available to Operating Management, the Company recognizes that significant additional effort will be required to improve reporting accuracy. Areas requiring improvement include:

- Accuracy of planned cost details (labor, fleet, material, external services) versus actual costs (labor, fleet, material, external services)
- Data clean up-of historical SAP CU orders
- Improved cost collection and data accuracy for SAP Internal Maintenance orders
- Estimating accuracy of SAP CU orders
- Accuracy of completed number and/or footage for Cost per unit KPIs
- Investigation of reporting accuracy and benefits of SAP operational level costing.

This is a move in the right direction because unit costs of some repetitive work are being established and measured. There is presently not enough data to draw any conclusions.

iii. Benchmarking – Internal

Supervisors from both Electric Operations and Gas Operations mentioned that lessons learned are shared among different work groups during monthly management review meetings, though such sharing is seldom documented. There is often sharing of safety practices, but there is little comparison between groups on other performance measures. Productivity was not being measured in the past; therefore, there was little internal benchmarking on productivity.

iv. Benchmarking – External

Neither Electric Operations nor Gas Operations takes part in any industry benchmarking effort.

3. Conclusions

37. The new continuous improvement programs are progressing well, even though the validation of cost savings is handicapped by IUSA's inability to isolate those savings resulting from productivity improvement.

Since forming the Business Transformation (BT) Department to align employees, processes and technology with the Company's business strategies and vision, a couple of continuous improvement programs, Rapid Results and Workout Methodology, were initiated in the beginning of 2010 and progressing well. Rapid Results are currently launching Wave 5. With a dedicated organization to focus on managing the effort, the Company should be able to continue to improve in a sustainable manner.

38. Productivity measurement has not been a focus of IUSA management.

IUSA measures many aspects of performance, such as safety, reliability, customer services and budget adherence. However, none of the performance metrics has productivity measurement. To measure what got accomplished (output) is essential. To measure what got spent (input) is essential. To measure either one of those two separately is not enough. For effective productivity measurement, the relationship between what got spent to achieve what got accomplished must be established. Presently, almost no group in IUSA has such measurement as pay-for-performance goals. (For information on the effective productivity measurements to include under the holistic cost management program, refer to Cost Management Framework Section C-5 a, b, and c in Appendix A.)

39. There is little documentation on the implementation and effectiveness of lessons learned.

We found substantial levels of sharing of safety-related issues, and occasionally performance lessons learned. There are also no documentation and no follow-up to see if the lessons learned are effectively implemented. (For information regarding to the documentation on the implementation of lessons learned under the holistic cost management program, refer to Cost Management Framework Section C-12a in Appendix A.)

40. The Quality Assurance Program for Gas Operations is barely passable and the staffing level is too low to be considered adequate and effective; for Electric Operations, it cannot be acceptable in the long run to rely on supervisors or contracted contingent

based workers as the last line of defense in assuring quality and compliance of contractor's work. *(Recommendation #12)*

For Gas Operations, NYSEG and RG&E together performed over $40 million of physical work (in-house and contractors) in 2010. The responsibilities of the QA/QC coverage are very extensive. It is inconceivable to conclude that the Quality Assurance Program can be maintained with just two persons between the two Companies. The fact that only seven inspections were performed on work completed by the Company workforce is a strong indication that the organization is seriously understaffed. The recommendation for the Company to appropriately staff the existing Gas QA/QC group to support an effective QA/QC program is covered under the "Program and Project Planning and Management – Gas" Element (Chapter XII).

For Electric Operations, the processes are still being established, the manual is being developed to reflect the program, and then, the necessary QA/QC personnel will need to be put in place to maintain the integrity of work quality and compliance.

41. The collection of production data at the work order level adequately addresses production, but IUSA has not maximized use of data to manage productivity.

Most of the quantity information is actually available at the work order level. For example, some activities, such as gas leak, pole replacement, new service, and gas repair, are isolated on a per unit basis in each work order. For other activities, such as street lights, pole inspections, and valve inspections, the estimated quantity information is available within the work order. The Company should make good use of the quantity information along with the job-hours and costs captured at the work order level to monitor and analyze productivity.

42. Effective productivity measurement has been lacking, but development of new KPI items initiated in early 2010 is a step in the right direction, particularly if extended to all repetitive measurable property units in both the Electric and Gas Operations.

The Company recognized this weakness and last year formed a team to recommend new productivity measurements. This is a move in the right direction because unit costs of some repetitive work is being established and measured. This initiative was implemented in the beginning of 2011. To the extent possible, all Electric and Gas Operations repetitive work should be measured and become the basis for annual bottom-up budgeting. (For information on the effective productivity measurement under the holistic cost management program, refer to Cost Management Framework Section C-5a in Appendix A.)

43. Analysis of performance metrics, in general, is inadequate, with few early warnings of potential problems or recommendations for corrective actions to mitigate factors that threaten targets.

Almost all the performance metrics are published for information only. Most of them have no narratives, and do not offer any explanations to some obvious problem areas. There is little analysis to address the issues, to recommend corrective actions, or to forecast whether this particular problem item will recover or miss the target at the end of the year. (For information on the analysis of performance metrics under the holistic cost management program, refer to Cost Management Framework Section C-5d in Appendix A.)

44. There is little effort in benchmarking internally.

In the past, there was informal sharing of lessons learned. Since productivity was seldom measured, there was no official internal benchmarking effort. New productivity measures are being developed. When the integrity of the historical data can be validated, internal benchmarking effort can begin. (For information on the internal benchmarking under the holistic cost management program, refer to Cost Management Framework Section C-12a in Appendix A.)

45. There is no participation in external benchmarking.

Neither Electric nor Gas Operation participated in any external benchmarking efforts. Electric Operations did not participate in Electric Utility Cost Group (EUCG) or PA Consulting. Gas Operations did not participate in American Gas Association (AGA). Both Electric and Gas did not participate in the Public Service Electric & Gas Peer Panel Benchmarking Symposium, which is free. The Company has planned to participate in an external benchmarking effort with First Quartile Consulting. (For information on external benchmarking under the holistic cost management program, refer to Cost Management Framework Section C-12b in Appendix A.)

4. Recommendations

12. Establish a Quality Assurance Organization to maintain the integrity of all the electric work performed. *(Conclusion # 40 this section; also Conclusion #34 of Resource Management section)*

The Electrical Operations presently does not have a Quality Assurance/Quality Control Program. For in-house electric construction crews, the field supervisors provide for quality assurance. For contracted electric construction crews, the Company utilizes about 20 contingent based workers (retired line supervisors) as “gatekeepers” to provide oversight and quality assurance. For the period 2008 through 2010, no formal Quality Assurance Group existed in Electric Operations. Field inspections were typically performed by the Line and Substation organizations.

A project to develop a Quality Assurance program for electric construction projects is currently underway. Engineering will provide a documented program for quality assurance and quality control for capital and large operations and maintenance programs across IUSA’s T&D business functions.

It is not desirable for Electric Operations to rely on supervisors and especially contingent workers to be its last line of defense when it comes to assurance of electric work quality. In the effort to develop the QA program, it is essential that the following attributes, similar to the Gas Operations Quality Assurance Program, are to be addressed: Management Oversight, Organization, Design Control, Procurement, Document Control, Control of Materials, Parts and Components, Special Processes, Inspection, Control of Measuring and Test Equipment, Inspection and Operating Status, Audits, Training, Corrective Action, Records, Nonconforming Materials Or Components.

A QA/QC Manual should definitely be developed to cover the following key areas:

1. Audits

2. QA/QC Materials and Specifications
3. Quality Assurance Field Inspections
4. Non-Conformances
5. Receipt Inspections
6. Corrective Action Reports.

Initially, Electric Quality Assurance personnel are needed to coordinate the formulation of the Electric Quality Assurance Program. A QA/QC organization needs to be established to be responsible to perform audits and inspections of activities affecting the safe operation of electric transmission, distribution and substation systems. Electric Operations Quality Assurance personnel should have sufficient authority and organizational freedom to identify quality problems; to initiate, recommend, or provide solutions; and to verify implementation of solutions. These personnel report to a management level such that this required authority and organizational freedom, including sufficient independence from cost and schedule when opposed to safe considerations, is provided.

The major quality assurance functions are to assure that an appropriate quality assurance program is established and effectively executed, and to verify, such as by checking, auditing, and inspection, that activities affecting quality have been correctly performed in accordance with procedures and regulations.

NYSEG and RG&E together performed over $120 million of physical work (in-house and contractors) in 2010. It is difficult to assess initially what the right size of the QA organization should be. Gas Operations QA organization oversees an annual Gas Operations of $40 million. The Electric Operations organization should at least start with a staffing of five, two supervisors-Engineering and three Lead Analysts -Engineering. Field Supervisors and contingent workers will still have to be used for QC inspection for field work.

We anticipate increase costs of $300K annually. The size of the underlying physical work makes even extremely marginal increases in safety, reliability, and quality more than sufficient to justify this increase.

Chapter XIII: Appendix A

COST MANAGEMENT FRAMEWORK

(A) Elements of A Guiding Philosophy:

1. Executive commitment
   a) Communicate cost control expectations
   b) Empower an independent cost oversight organization
   c) Maintain constant visibility and cost emphasis throughout the year
2. The priority of cost management
   a) Provide a place for cost in the hierarchy of priorities
   b) Include cost management metrics in pay-for-performance goals
   c) Require a price tag, no matter how crude, for any proposed solutions to identified issues
3. Independent oversight
   a) Establish a cost management organization with the director reporting to COO
   b) Assign all cost related functions under the purview of the cost management director
   c) Build an efficient cost control/service network by assigning cost professionals (cost engineers or cost analysts) to the responsible line managers while maintaining their technical direction from the cost management director
4. A coherent statement of policy
   a) Include cost management philosophy in vision, mission, strategies and goals at the senior management level
   b) Reflect cost management objectives in the work plans at the working level
   c) Emphasize cost control in addition to financial oversight
5. A strong cost culture
   a) Display a high degree of cost awareness at all levels
   b) Prudently balance costs versus risks in decision making
   c) Maintain accountability of each individual for optimizing costs

(B) Elements of A Structured Cost Management Plan:

1. A well communicated plan
   a) Publish official document
   b) Review status monthly
   c) Post relevant cost management information on Company and Business Transformation Websites
2. A formal process
   a) Delineate how costs will be managed
   b) Define objectives and expectations
   c) Identify essential cost elements
   d) Design a plan of implementation
3. Organizational responsibilities
   a) Identify overall accountability of each major process
   b) Evaluate and concur with plan by all the major work groups
   c) Monitor compliance to the plan by all participating managers

4. A focus on "cost control" instead of "cost oversight"
    a) In process – real time, not after-the-fact
    b) Anticipatory – proactive, not reactive
    c) Managing, not reporting
    d) Integral participation, not arm's-length involvement
    e) Focus on analysis, not numbers
    f) Focus on improvement, not measurement
5. A focus on cost drivers
    a) Identify cost trends early
    b) Perform insightful analysis from available data
    c) Evaluate cost versus risk on major scope growth items
    d) Take timely intervention to mitigate cost overruns

(C) Elements of Cost Management Building Blocks:

1. Management systems versus monitoring systems
    a) Develop a proactive mode of operation to anticipate potential problems
    b) Design a cost trend program as an early warning system
    c) Institute a rigorous project management process
    d) Adopt a risk assessment program to better evaluate exposure to cost and scope growth
2. Credible cost control baselines
    a) Prepare sound capital and O&M budgets
    b) Develop comprehensive cost estimates for major capital and O&M projects
    c) Calculate the unit cost or unit job-hours of measurable work items based on quantities and standard productivity rates
3. Accurate cost collection
    a) Continue to use SAP for capital and O&M cost reporting
    b) Assess SAP to see if the system can be enhanced to monitor productivity of measurable work items
    c) Assess SAP to see if the estimated and actual company job hours are available and credible
    d) Collect contractor job hours, except for lump sum or specialty contracts
4. A Focus on Work Force Performance
    a) Establish productivity metrics to measure the performance of the physical workers at the work group and regional levels
    b) Perform in-depth analysis to identify root causes that impacted productivity, and provide recommendations to mitigate similar situations in future
    c) Review periodically to evaluate if the implementation of recommendation is effective in improving productivity
5. Effective performance measures
    a) Establish productivity metrics that relate input (job hours) to output (production); for repetitive measurable work items, that will be the unit job-hour rate
    b) Develop a more complete set of metrics (Balanced Scorecard) to measure performance in all key areas, namely, (a) Safety, (b) Operation Excellence, (c) Customer Satisfaction, and (d) Cost Management (some key cost or productivity performance indicators in addition to budget performance)
    c) Provide instant linkage of measures from senior VP to regional manager levels

   d) Include in-depth analysis (with corrective action recommendations and potential cost impacts) in metrics that are not meeting or on the verge of not meeting objectives

6. Targeted initiatives
   a) Set up special effort or task force to attack major problems identified
   b) Assess the magnitude of total cost impact
   c) Monitor the progress and continuous cost impact until the effort is completed
7. Skilled cost professionals
   a) Develop a force of qualified cost professionals (cost engineers or cost analysts) to implement and support all aspects of the holistic cost management program
   b) Educate the cost professionals to fully understand the business side of Electric Operations and Gas Operations
   c) Train the field cost professionals on the following primary responsibilities:
      - Performing cost analysis
      - Analyzing productivity
      - Recommending corrective actions
   d) Continue to upgrade the cost control techniques and business analytical skills of all the cost professionals in the whole Company
8. Establishment of cost control/service network
   a) Assign a field cost professional to cover every region in Electric Operations as well as Gas Operation (a cost professional can cover multiple regions, as appropriate)
   b) Provide cost support functions to the regional managers
   c) Assist the accountable managers to fulfill their cost management responsibilities
9. A focus on analysis
   a) Perform insightful root cause analysis on substantial deviations from cost control baseline
   b) Develop predictive analysis of expected final costs
   c) Provide recommendations and corrective action plans for major unfavorable deviations
10. A focus on corrective action
    a) Develop an attitude of ready intervention
    b) Be ready to resolve problems with innovation and boldness
    c) Tally cost avoidance or cost savings on successful efforts
11. Continuous improvement
    a) Continue to use the Rapid Results and Workout programs that:
       - Define major initiatives
       - Perform cost/benefit evaluation
       - Document resulting intangible benefits and cost savings, if any
12. Benchmarking
    a) Internal Benchmarking: Implement a formal, structured program for the regional representatives to:
       - Share success stories on work units with superior productivity rates
       - Document commitment to adopt shared methods or lessons learned
       - Prove effectiveness of implementation in other regions in terms of cost savings achieved
    b) External Benchmarking:

Designate a few cost professionals as Company representatives to participate in EUCG (Electric Utility Cost Group) and PSE&G Peer Panel (Benchmarking Symposium) to:

- Network with industry peer professionals
- Exchange continuous improvement ideas
- Identify relevant best practices for internal implementation
- Likewise, designate a few cost professionals as Company representatives to participate in AGA benchmarking effort, but also participate in PSE&G Peer Panel.

Plans, Controls, Performance Management, and Compensation

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XIV. Plans, Controls, Performance Management, and Compensation

A. Corporate Plans - Findings

1. Vision and Values

a. ISA Global

ISA uses its "Group Code of Ethics" to express its vision and values, centered around the statement that:

> *We aspire to be the preferred global energy company because of our commitment to the creation of value, quality of life, the safety of people and of supply, the protection of the environment and customer focus.*

ISA supports this general statement with six values:

- Corporate Ethics and Responsibility
  - Good governance generally recognized in international markets
  - Principals of business ethics
  - Transparency
  - Furtherance of the common interest of shareholders
  - Consideration of other legitimate public and private interests
  - Engagement in and learning from the cultural and social realities of territories and communities served
- Economic Results
  - Achievement of the strategic plan's growth and profitability objectives
  - Operation with the framework of a diversified Group, organized around the parent company and subject Group common guidelines
- Respect for the environment
  - Focus on the development of clean energy and respect for the environment
- Sense Of Belonging And Trust
  - Firm and permanent ties with stakeholders
  - Giving stakeholders a sense of belonging to an excellent Company
  - Producing among stakeholders a feeling of being an integral part of company plans
  - Inspiring trust among all who participate in and deal with the Company
- Safety and Reliability
  - Energy supply and other activities provided in a safe, reliable environment
  - Best practices in safety and prevention
- Customer Focus
  - Understanding customer needs and expectations
  - Continuous improvement in customer satisfaction and attachment
  - Highest service quality while complying with regulatory obligations.

b. IUSA

IUSA operates under the following mission statement:

> *Iberdrola USA is a team of dedicated individuals working as one to deliver value to our customers, employees and shareholders. By providing outstanding customer service and exceptional reliability, while holding safety and the environment in high regard, we aspire to be a world-class energy company.*

IUSA supports this mission statement with what it terms its "Strategic Planning Principles" and "Big Goals." These principles consist of:

- High quality, safe, reliable, and cost effective customer service
- High-performing, diverse work force created by engagement, development, and reward
- Business growth through prudent investment
- Investment in technology to improve performance and efficiency
- Use of information and data for continuous business improvement
- Trust and respect of key stakeholders
- Respect for the environment and delivery of positive long-term results.

2. Corporate Plans

a. ISA

ISA reports that it has defined a strategy to implement the six Global values cited above. We asked for that plan. Instead, ISA provided the set of slides used to address results, drivers, and projections for a regular conference it holds with investors, expressing the view that they "may provide some useful information regarding strategy." When asked about the ISA planning process, senior ISA executive management focused not on internal development, but on preparation for the delivery of the presentation made on "Investor Day" in February or March of each year. This presentation was described as the focus of strategic or corporate planning at ISA.

ISA does not each year revise the elements of that presentation that address (albeit not in the form of a structured "plan") strategic and primary business objectives and measures each year. The investor presentation did, however show current measures of performance against a number of those objectives and measures. The revision cycle for the objectives and measures are typically three to four years (the current covers 2010 through 2012). Senior executive management in Spain emphasized and discussed the investor-day "plan" only in terms of financial metrics. That emphasis is consistent with the audience one would expect for such a presentation and with the content provided to us. The material, however, did address certain other narrative and quantitative environmental (*e.g.*, utility regulatory conditions) and operating statistics (*e.g.*, customers, sales, employee numbers, expected capital expenditures).

b. IUSA

A Director, Business Strategy, reporting to the Vice President-Business Transformation has had responsibility for the IUSA business planning process. This vice president works for the COO. The director has responsibility for evaluating industry trends, developing the plan, evaluating the plan, and performing financial control over the Business Transformation process, which IUSA has been employing to look comprehensively at ways to improve its business processes and activities.

Our review of IUSA board minutes did not disclose discussion of or participation in strategic or corporate planning or plans. Many U.S. utility boards conduct periodic (as frequent as annual) sessions focused on strategic plans.

ISA executive leadership and the parent board do not become actively engaged in the creation of IUSA strategic plans, in deference to the stated approach of leaving local operations to local leadership. The ISA role is to ensure that the plans conform to and are consistent with the general plans adopted by the ISA board. There is top-level guidance from Spain for the IUSA planning process, however, at least as it concerns financial planning. The Networks units (which include IUSA utility operations) begin their planning from top-down financial targets provided from Spain. These targets operate as guidelines under which IUSA develops and presents its needs. The leadership of the Networks Group in Spain then reports that it examines the requests of each of the units (our countries, essentially), tests them for conformity with the top-down limits, and seeks to consider unique, special requirements and balance the amounts requested to the extent that cumulative requests from the countries might exceed then-established limits from top Spanish management. More senior executive management in Spain observed, however, that this role is not expected of the head of the Networks Group, suggesting that such balancing is not required at all.

IUSA corporate planning springs from the planning principles, focusing on the development of priorities and goals, using a five-year window. IUSA's strategic plan reports specific strategic priorities by unit. As the following bullets demonstrate, these items represent a mix of specific targets, more general statements (akin to purpose statements for the functions), and items specific to targeted current goals, versus expectations likely to continue from year to year. The bullets summarize the strategic priorities from the 2011-2015 plan, which appears to have been documented in October of 2010:

- NYSEG/RG&E
    - Align programs to produce a safe, engaged, inclusive, high-performing work force
    - Exceed service-quality, safety, and environmental objectives
    - Achieve or exceed allowed returns
    - Improve regulatory and stakeholder relationships
    - Analyze NYSEG/RG&E merger
    - Identify credible New York transmission investment opportunities
    - Complete the management audit, addressing all issues, and minimizing incremental net costs
- Central Maine Power
    - Align programs to produce a safe, engaged, inclusive, high-performing work force
    - Exceed service-quality, and environmental objectives
    - Implement Advanced Metering Initiative Project
    - Achieve MPRP (a major Maine transmission project) construction and budget
    - Capitalize on new transmission opportunities
- Customer Service
    - Align programs to produce a safe, engaged, inclusive, high-performing work force

- Achieve best-in-class customer service satisfaction in Northeast
- Get uncollectibles below 1 percent of revenues
- Achieve lowest cost to serve in Northeast

- Business Transformation
  - Align programs to produce a safe, engaged, inclusive, high-performing workforce
  - Implement best practices using benchmarking and process re-engineering
  - Facilitate increase in process and performance efficiencies year over year
  - Generate growth opportunities that increase EBITDA
  - Align priorities of IUSA functions through coordinated strategic planning
- Engineering and asset management
  - Align programs to produce a safe, engaged, inclusive, high-performing workforce
  - Develop a single engineering organization by implementing common standards and processes
  - Create asset management and investment prioritization program
  - Deliver capital plan under effective, consistent project management
  - Implement effective maintenance programs to optimize safety and reliability
- Electric Operations
  - Align programs to produce a safe, engaged, inclusive, high-performing work force
  - Develop metrics for storm measurement and standardize storm-response approach
  - Virtualize functions to improve outage management and storm recovery
  - Automate field planning functions for day-to-day and storm-response efforts
- Gas Operations
  - Align programs to produce a safe, engaged, inclusive, high-performing work force
  - Establish and maintain fiscal management in field operations
  - Achieve benchmarks for rate-case mandated safety, quality, and mandated O&M
  - Achieve safety performance measures
  - Eliminate paper processes and improve field access to information
- IT
  - Align programs to produce a safe, engaged, inclusive, high-performing work force
  - Deploy field work force automation and mobility technologies
  - Simplify user access to business information
  - “Realize” the IUSA Smart Grid Strategy
  - Implement best security practices
  - Investment in regulated T&D infrastructure, focusing on environmental responsibility
- HR
  - Align programs to produce a safe, engaged, inclusive, high-performing work force
  - Improve costs through synergies with Spain
  - Assess skills gaps and implement world-class talent management, succession planning and diversity programs
  - Cultivate partnerships with labor and business are leaders to improve relationships
- Environmental, Health, and Safety

  - Reduce employee injuries, severity and vehicle incidents by 5 percent
  - Implement compliance assurance program with annual audits
  - Reduce liability from $30 million to $1 million across 10 years
  - Seek best practices within ISA Group
- Security
  - Meet NERC Critical Infrastructure requirements
  - Minimize security risk and reduce achieve operating costs
  - Implement Global Traveler Locator system
- General Services
  - Align programs to produce a safe, engaged, inclusive, high-performing work force
  - Implement property management optimization recommendations
  - Deliver safe, reliable, cost effective facilities management
  - Align with various models
  - Invest to maintain safe, reliable, economical vehicles and equipment
- Legal
  - Reduce overall costs and improve service quality
  - Move all resources to IUMC and add regulatory and commercial skills
  - Increase legal support for regulatory initiatives
  - Improve understanding of and compliance with ISA governance model
  - Improve compliance with NERC and FERC reliability requirements
  - Participate in ISA best practices initiatives
- Regulatory
  - Assure compliance with merger and rate case conditions
  - Develop regulatory relationships
  - Conduct a professional management audit
  - Prepare and file rate cases if needed for New York companies in 2012
  - Identify credible new transmission investment opportunities
  - Analyze legal consolidation of NYSEG and RG&E
  - Provide accounting guidance on regulatory matters
- Treasury
  - Provide effective, efficient cash-management
  - Maintain optimum utility capital structure
  - Execute financings cost effectively
- Purchasing
  - Manage supplier payment terms to quantified guidelines
  - Support the Maine AMI and MPRP purchasing requirements
  - Implement named tools reflective of ISA best practice
  - Generate purchasing cost savings of specified amounts
- Taxes
  - Identify added automation opportunities
  - Participate in ISA best practices identification
  - Provide tax services cost effectively and proactively
  - Identify cash tax savings and earnings contribution opportunities
  - Create training and succession programs to develop needed skill sets
- Finance and Accounting – Risk

    - Continual executive management monitoring and performance indicator review
    - Application of analysis and modeling approaches to assess risk
    - Mitigation of key risks
    - Communication of risk profile to key company leaders
- Non-Utility
    - Diversify and grow retail gas and electric base by [redacted] per year
    - Reduce environmental impact of district energy business
    - Increase employee performance through communications and training
    - Grow EBITDA and net income by [redacted] per year.

The IUSA corporate plans support each strategic priority with a list of what changes should occur and why they are important, concluding with a list of specific actions for making those changes happen. The actions are clearly sequenced across the five-year period that the plan addresses. The required actions are supported through the designation of specific projects having identified managers and support groups, statements of project purpose, and targeted completion dates.

B. Corporate Plans - Conclusions

1. IUSA operates under a clear and appropriate set of mission and vision statements and clearly stated corporate objectives, which IUSA makes clear and emphasizes throughout the organization.

The mission and vision statements are clear and they address values appropriate to IUSA's utility mission. IUSA associates a set of "big goals" with these statements, and, as addressed below, supports them with a cascading set of specific goals and objectives, which IUSA updates regularly. Communications from top IUSA management routinely reinforce the importance of big goals and strategic priorities, and reports on progress in meeting them.

2. IUSA's goals and objectives balance the needs of stakeholders, including customers, shareholders, employees and regulators.

IUSA has adopted strategic priorities at the department or functional level, and distinguishes them between the New York and Maine utility operations as well. These priorities address the interests of all stakeholders, and reflect current issues and emphases (*i.e.*, they are not static from year to year). IUSA in particular emphasizes Commission requirements in its specific and measurable goals and objectives. Two other strengths in IUSA's approach are:

- A comparatively high level of consistency as more general statements of values and priorities cascade down to function and individual goals and objectives
- Tying each high level objective or strategic priority into a defined set of change expectations, activities, responsibilities, and schedules.

These strengths contribute to a broad (but focused) and largely measurable set of goals and objectives.

We did observe a number of group-level strategic priorities that were less tangible (or more in the nature of purpose statements), but not at a level that undercuts a predominantly positive view of this aspect of performance.

3. **IUSA has recently adopted its first five-year plan, and recognizes, but has not yet advanced far in taking a much longer range view of its utility infrastructure.** *(Recommendation #1)*

Under the overall guidance of the Spanish executive assigned as co-COO of IUSA and remaining with the IUSA organization, IUSA has completed its first five-year capital plan. We found a general recognition of the value in taking a longer-range view of network requirements in a more “quantified” way, but not a concrete plan for doing so.

C. Corporate Plans - Recommendations

1. **Study and apply the ConEd experience in long-term infrastructure planning in forming a concrete plan for long-range infrastructure planning.** *(Conclusion #3, Chapter X Conclusion #2)*

The report addressing our recent management and operations audit of ConEd addresses general concerns about aging infrastructure. We found ConEd committed to examining the challenges to long-range network planning, given the importance of maintaining reliability and need to address questions of long-term affordability. The networks, customer bases, economic conditions, and other driving factors of metropolitan New York City certainly are not the same as those in the widely dispersed areas of New York served by IUSA. Management at both companies, however, share concerns about what it will take to maintain a robust delivery network over the long term.

We also recognized that in asking ConEd (as we ask IUSA here) to become more analytical and quantitative when looking over the long term, we were inviting a course not well charted yet in the industry. We have not remained privy to what ConEd has been doing since our audit, but do find encouragement in general reports of progress from the company and from Public Service Department personnel who have been working together in implementing certain key recommendations from that audit.

We believe that benefit can come to IUSA from learning what can be shared about that effort. Thereafter, it would be our expectation that IUSA would combine that learning experience with its own expressed concerns about maintaining the health of its network at affordable costs over the very long-term (10 to 20 years) to generate a specific plan and schedule for extending its planning horizon beyond the level that has supported its recent development of a five-year capital plan. We emphasize that a primary purpose of this recommendation, as was the case with ConEd, is also to increase transparency between IUSA and Department staff in ways that will better inform key regulatory decisions that affect reliability and customer cost. Therefore, we believe that a commonly identified approach, timing, and results (although clearly to be carried out by the Company) are critical to achieving the benefits that this recommendation can produce.

This recommendation is closely related to and should be executed in tandem with Recommendation #2 from the Budgeting chapter of this report.

D. Controls - Findings

1. Sarbanes Oxley

We begin with this subject in light of the attention that Sarbanes Oxley received in the Commission's order authorizing ISA's acquisition of Energy East. The order provides that:

> *After the closing of this acquisition Energy East must continue to comply with the provisions of the Sarbanes-Oxley Act (SOX) as if it were still bound directly by the provisions of the SOX. Energy East's periodic statutory financial reports must continue to include certifications provided by its officers concerning compliance with SOX requirements as if still bound directly by the provisions of SOX.*

The structure adopted during Energy East's ownership of NYSEG and RG&E for adopting, applying, testing, changing, and validating controls was guided by Sarbanes Oxley (SOX) requirements and industry experience following their implementation. IUSA continues to use the same overall structure. IUSA's structure is typical of others we have seen, in that:

- Management has responsibility for establishing and maintaining internal controls and for ensuring their effective operation.
- Controller's organization has responsibility for maintaining the integrity of documentation.
- Internal Audit periodically tests the effectiveness of the key controls and pursues and gaps or deficiencies identified.
- External Auditor periodically tests the effectiveness of key controls, follows up on any deficiencies, and issues an opinion on the effectiveness of the internal controls system.

IUSA operates under documented procedures for assessing and testing internal controls under what one would describe as a SOX-like structure. The process continues to operate under the general structure that applied under Energy East ownership (*i.e.*, when SOX requirements applied independently of Commission order). Earlier portions of this chapter reported on a continued, significant level of Internal Audit work to test controls.

IUSA has been continuing its SOX-type work guided by the understanding that the commitment required under the merger order is continuing what was being done under Energy East. IUSA has been reducing SOX key controls for some time. Internal Audit leadership believes that the reduction can be to as few as about 400 key controls, while the outside auditor believes that a number in the range of 300 may be achievable. The reduction started from a baseline of about 1,200 key controls. That number has been reduced to about 500, by removing the "key" designation from many. A drop of 150 in the last year was the biggest single, annual drop since the reductions began. The reductions have resulted from annual process reviews and controls matchups that begin with management. A checklist allows management, IA, and the outside auditors to check-off any that can be de-keyed. Management makes the final decisions, but has reportedly never dropped a key control without the support of IA and the outside auditors. The "dekeying" process now long underway with respect to SOX controls has not undergone a process of examining key controls from a specific "regulatory" versus the "financial" perspective, which IUSA (unlike Liberty) views as including regulatory matters.

Controls at the ISA level fall under the head of Administration and Control in Spain. Spain has no SOX equivalent. ISA seeks the same objectives, but the head of Administration and Control considers SOX to be an inefficient, burdensome way to achieve control, involving much expense and "paperwork" relative to the benefits he believes it produces. IUSA now comprises the only exception to how controls systems operate, with the differences due to the U.S. SOX requirements. He reported that his organization does not know the specific details of SOX requirements, and is not directly involved in how U.S. meets its commitment to continue meeting SOX-like requirements.

2. Auditing

Internal Audit at major U.S. utility (and other) corporations forms a central link in assuring effective controls. IUSA's Internal Audit organization plays the predominant role in planning and executing an audit program for IUSA, under overall process coordination by ISA's global audit organization in Spain. SOX testing forms an important part of IUSA Internal Audit's activities each year.

a. Internal Audit Organizations

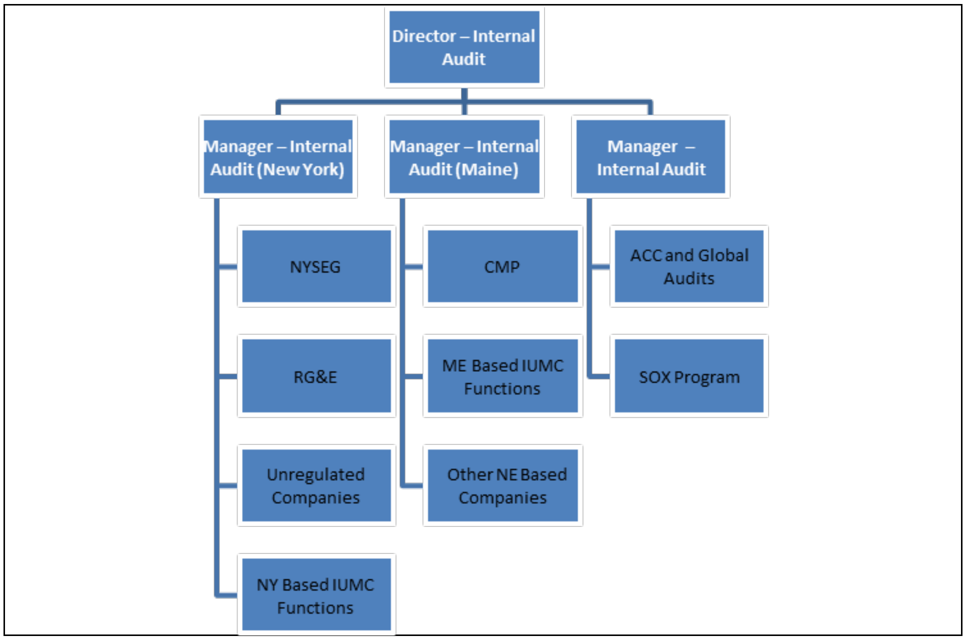
IUSA and ISA each operate an internal audit organization (IA). ISA refers to its IA organization as Global IA. Global IA has responsibility to assure (and IUSA IA to support) coordination of audit activities, but policies and procedures emphasize the operational independence of lower level (such as IUSA) IA organizations. The next chart shows the Global ISA organization.

Global Internal Audit Organization

[redacted]

IUMC houses IUSA's IA organization, and employs all the U.S. auditors. There are 10 IUSA IA auditors and an administrative assistant. Four IUSA auditors work from Rochester, three from Binghamton, and three from Maine. The next chart shows IUSA's IA organization.

IUSA Internal Audit Organization



b. Internal Audit Policies and Procedures

The Global and the IUSA IA organizations operate under an ISA board-approved governing document (last amended in November 2010) entitled the “Internal Audit Basic Regulation.” This document:

- Defines IA’s organization, responsibilities, operations, and activities
- Structures relationships between IA and other groups
- Provides for coordination and information exchange with IA groups in each business area (as shown in the Global IA organization chart).

This document establishes Global IA as an independently operating function, whose primary responsibility is to analyse, assess, and supervise internal control and risk management systems at the parent and subsidiary levels. Specific Global IA activities include:

- Monitoring the reliability of financial information, the systems that process such information, and the accuracy of required, periodic releases of financial information
- Supervise the Financial Information Internal Control System (FIICS) used throughout ISA entities
- Conducting an annual assessment of Code of Ethics compliance
- Issuing opinions on the compliance of investment and divestment decision opinions with the Investment/Disposals and Project Development Regulations
- Auditing the risk control and management system defined in the Risk Control and Management Policy
- Auditing the process for setting and evaluating targets to verify conformity with the Management by Objectives Process Guide
- Supporting and assisting subsidiary-level divisions with internal control
- Supervising the IT risk-control system

- Supervising planning and implementation of internal audit programs, monitoring professional skills, and improving the efficiency of the corporate management systems
- Monitoring Management-System objectives at all entities to ensure alignment with the Strategic Plan
- Collaborating with the Code of Ethics Committee to supervise compliance with the Crime Prevention and Anti-Fraud Policy.

Global IA and IUSA IA must present, to their respective board audit committees, annual audit plans. Following A&RSC approval, senior management and division heads meet with the head of IA to allow for explanation of the annual plan details for ISA Global. The head of Global IA presents to the A&RSC committee at the end of each year a report addressing execution of the annual audit plan.

IUSA IA makes a similar report to its audit committee. The issuances of this report include recommendations for addressing issues identified as a result of the year's audit activities. More detailed procedures for conducting IA activities come in the form of a Management Model for the Internal Audit Area. This model must provide for a "Quality System," and include a Quality Manual and procedures. The IUSA IA group's actions must conform to the Management Model and Quality Systems.

ISA and IUSA employ their own, but identical methods for appointing heads of IA and approving annual audit budgets. The chairman of the board has the right to propose, and the audit committee to approve appointments and removals of the head of IA. Annual budget proposals come first before the audit committees; after their approval, the chairman of the board presents the budgets for full board approval.

c. IUSA's Audit Planning Process

Planning takes place in the last quarter of the year preceding the plan's execution. Detailed procedures cover the steps involved in plan preparation and execution. The sources for identifying potential audit activities include:

- Corporate objectives and IA's Annual Objectives Plan
- Requests from the audit committee and from the Chairman and CEO.
- Results of risk assessment of business objectives and activities
- Requests from business areas and from IA
- Previous year's potential audits.

The resulting, candidate audit activities then undergo prioritization and assessment relative to available audit resources, in order to produce a decision on their inclusion in the annual plan. Each item included in the annual plan is then subjected to a potential work file, for inclusion in the Internal Audit Management system. The IUSA A&CC approved IUSA's "2011 Audit Risk Assessment and Annual Audit Plan" in December 2011.

There are monthly coordination meetings among the internal audit groups at ISA and the subholding companies. A primary purpose is to assure that all ISA units operate in accord with best international standards, seeking, as the ISA head of Internal Audit describes it to make Iberdrola a benchmark for the profession. The head of Internal Audit in Spain reviews the draft audit plan prepared by IUSA Internal Audit. Each subholding company prepares those plans according to common, ISA-wide guidelines. One of the regular monthly ISA-wide Internal Audit meetings entails (generally in November) discussion and comment on the draft plans of each subholding company. Following those discussions, each unit's Internal Audit head returns home to complete plans and present them to the audit committee of the subholding company (IUSA in the U.S.) board of directors. As the year progresses, the head of Internal Audit at ISA examines the quarterly reports that each subholding company's Internal Audit group prepares for their individual board audit committees. The purpose of this review is to identify any items reportable in ISA's consolidated quarterly financial results reporting.

d. Recent IUSA IA Plans

Entity	Hours	Entity	Hours
CMP	1,100	IT	1,900
Corporate	10,120	CT Gas	700
NY	5,820	Non-Utility	440
		Total	***20,080***

The next table shows the division of 2010 audit hours by IUSA business area. The 2010 audit plan refers to the continuation of SOX compliance as required by the Commission order authorizing ISA's acquisition of Energy East. IUSA IA used 2009 SOX audit plans as a template for 2010, assigning 4,000 hours to SOX-related work. The 2010 plan included a 400-hour affiliate-transactions work item titled "Determine if costs incurred for Team NY are properly allocated to NYSEG and RGE."

The 2011 IUSA internal audit called for 16,005 hours dedicated to specific works. This sum represents a 20 percent reduction from 2,010 hours. Note that the sale of IUSA's New England gas distribution utilities occurred in 2010. SOX-related work fell by 25 percent in 2011, to 2,968 hours. The 2011 plan proposes only moderate use of external resources, with a 2011 budget of [redacted] and a 2010 budget of [redacted] for outside fees for specialized IT audits. The plan reported that its principal focuses are (in the order listed):

[redacted]

e. Recent IUSA Audits

ISA IA performed about 120 audits in 2009 and 2010. None focused on New York operational effectiveness; they had a largely financial focus. One audit in this period addressed affiliate transactions. The next table summarizes the audit reports issued by IUSA since 2008.

Year	Number	Affiliates	Operations*
2008	8	0	0
2009	20	0	Pressure Regulation; Problem/Incident Management
2010	20	1	NPPC/NERC Standards; Business Continuity

*Excluding IT

The 2010 affiliates' audit (report dated September 2010) was the first performed since 2007. It examined:

- The 11 Affiliate Service Agreements involving New York utility operations
- The 2008 Energy East–ISA Service Agreement
- NYPSC Code of Conduct requirements and RG&E and NYSEG 2010 reports
- Process for calculating the NYSEG Storage, Freight and Overhead rate
- Process for calculating NYSEG and RG&E Occupancy Overhead and Payroll Overhead Rates
- Invoices among IUMC, NYSEG, and RG&E
- Monthly reconciliation of IUMC and Affiliates Accounts Receivable versus Accounts Payable balances
- Process for calculating the Global Allocation factors for NYSEG and RG&E.

The work tested the application of the listed processes on a sample basis, finding no exceptions. The work did not examine the reasonableness of any of the factors or underlying calculations.

Internal Audit performed another examination of affiliate matters in 2011. It examined and found appropriate the:

- Accounting procedures and internal controls over affiliate transactions
- IUMC-to-utility billing allocations and support
- Review of affiliate billings by utility personnel
- Sufficiency of billing detail to support that review
- Conformity billings from ISA with signed service agreements
- Charges for International Employees to the utilities.

The 2011 audit did, however, make a number of recommendations for improvement:

- Replace the outdated cost allocation manual included on the Company website
- Assure that there are signed and retained agreements covering internationally assigned employees
- Address the absence of policies and procedures governing international work assignments by creating ones addressing time reporting, available allowances and the accounting for payroll and allowances
- Eliminate use of default allocator to charge time of personnel supporting the work of IUSA executives
- Correct inability to trace allowance expenses for international employees from Spain working in the U.S. and two IUMC employees working in Spain
- Accrue billings from ISA (a change from simple, annual billing) monthly, in recognition of code-of-conduct requirements
- Remove costs for fleet vehicles assigned to international employees from the utilities and charge them to the holding company

A Liberty data request for copies of documents tracking implementation of any changes resulting from the audit prompted a response that IUSA did not have any.

f. IUSA Audit Resources

The next table demonstrates that IUSA IA has a staff with long tenure at the Company. It shows 2010 staffing. Staffing fell in 2011 by two persons; *i.e.*, the same number assigned to Connecticut in 2010 before the divestiture of New England gas operations. A new audit director replaced the retiring incumbent as well. He accumulated over 15 years of accounting experience in the banking industry before joining RG&E in 1996.

Position	Location	Experience	Education Certifications
Audit Director	Ithaca Binghamton	26+ Yrs Auditing NYSEG/Energy East 2+ Yrs Public Accounting 2+ Yrs Accounting	BBA CPA
Lead Auditor	Ithaca Binghamton	31 Yrs Auditing NYSEG/Energy East 2+ Yrs Public Accounting	BS
Lead Auditor	Ithaca Binghamton	18 Yrs Auditing NYSEG/Energy East 1+ Yrs Public Accounting 5 Yrs Publishing/Retail Accounting	BBA CPA, CFE
Lead Auditor	Ithaca Binghamton	21 Yrs Auditing NYSEG/Energy East 3+ Yrs Public Accounting	BS
Lead Auditor	Ithaca Binghamton	12+ Yrs Auditing NYSEG/Energy East 24 Yrs Financial Accounting NYSEG	BAA
Audit Manager	Hartford	POSITION VACANT	
Lead Auditor	Hartford	18 Yrs Auditing SCG/CNG/Energy East 1+ Yrs Director of Customer Support 8 Yrs Internal Auditing @ NU	BA, MBA CIA
Audit Manager	Augusta	8 Yrs Auditing CMP/Energy East 2 Yrs Treasury Operations CMP 21 Yrs Internal Auditing, 10 @ ME Yankee	BS, MS CTP, CIA
Audit Manager	Pineland	2 Yrs Auditing Energy East 3 Yrs Audit Manager International Technology Company 1 Yr Internal Auditing Consulting Firm 4 Yrs Public Accounting	BA CICA
Audit Manager	Rochester	11+ Yrs Auditing RGE/Energy East 2 Yrs Inspection/Environmental RGE 12+ Years Various Auditing Positions Chase Manhattan Bank	BS CIA
Lead Auditor	Rochester	18 Yrs Computer Programmer NYSEG 10 Yrs Information Technology Auditing NYSEG/Energy East	BS CISA
Lead Auditor	Rochester	4 Yrs Auditing Energy East 7 Yrs Auditing Banking Industry 1 Yr Public Accounting	BS

CIA	Certified Internal Auditor	CISA	Certified Information Systems Auditor
CPA	Certified Public Accountant	CFE	Certified Fraud Auditor
CTP	Certified Treasury Professional	CICA	Certified Internal Control Auditor

3. Ethics and Compliance

IUSA's Ethics and Compliance Office directs the U.S. Ethics and Compliance Program. IUSA also has a Code of Conduct, which applies to all employees, officers, and directors. This code covers a fairly typical range of subjects (*e.g.*, accuracy and non-destruction of records, FERC and NERC standards and requirements, harassment, discrimination, environmental protection, antitrust, insider trading, confidential and competitive information, intellectual property, relationship with authorities, political contributions and activities, bribes and kickbacks, and conflicts of interest. The code document:

- Establishes a sound perspective and "tone"
- Declares the board's Audit and Compliance Committee as the overseer of the Compliance Program
- Establishes a clear executive lead (the general counsel)
- Names compliance officers for each major IUSA business area (lawyers have been assigned to NYSEG/RG&E and to CMP)
- Provides for anonymous reporting of issues and concerns through a hotline and the internet
- Precludes reprisals for reporting
- Notes that disciplinary action, including dismissal may be a consequence of violations.

The affiliate transaction section is not particularly specific. Its substantive treatment of the issue simply states:

> *Transactions between a regulated utility and Iberdrola USA or its other regulated or non-regulated affiliates may be subject to sets of standards issued by the individual state commissions governing the regulated utility. In addition, these transactions may also be subject to rules set forth by the FERC. Employees will comply with all statutes, regulatory rules and orders, and accounting standards as they apply to transactions between affiliates. Affiliate transactions involve the provision, sale, assignment, transfer or lease of goods, services or other assets between a regulated utility and Iberdrola USA or its other affiliates. These standards and cost allocation requirements are referred to as affiliate rules. They were issued to ensure that transactions between a regulated utility and Iberdrola USA or its affiliates are appropriate. They protect against the regulated utility showing favoritism toward its affiliates, sharing certain information with affiliates or applying inappropriate affiliates' costs to the regulated utility.*

IUSA also has adopted related ISA policies (Crime Prevention and Anti-Fraud and Good Tax Practices). IUSA reports that it is considering the adoption of the ISA Code of Ethics.

The ISA A&RSC Committee has responsibility to establish and supervise a means for permitting anonymous reporting by employees. Documented procedures provide for e-mail and regular mail notification, assure anonymity, and assure no retaliation for good faith reporting.

E. Controls - Conclusions

4. IUSA has continued to address SOX compliance under the structure and with the methods used prior to ISA's acquisition

The overall structure, alignment of responsibilities, procedures, and practices for addressing SOX particularly, and for maintaining effective controls has remained largely unchanged under ISA. Internal Auditing and the independent accountants remain engaged in central testing roles and offer continuing input with respect to industry developments. We found the structure, responsibility alignment, procedures, practices, number of key controls, and testing time dedicated representative.

5. Reductions in key controls have occurred without an examination of their significance from a regulatory point of view. *(Recommendation #2)*

Many U.S. companies have been reducing the number of key controls and seeking to bring greater efficiency to what is universally acknowledged as an extremely resource-intensive process of controls testing. As "de-keying" a control can substantially increase the cycle time for testing (the prevailing practice being to test key controls annually and others less frequently), this practice can generate substantial savings.

We have not observed a more than expected rate of reduction in key controls or testing hours of IUSA. However, significant reductions continue, and significant SOX controls review efforts formed important goals for 2011. Moreover, the head of control at the parent level in Spain has expressed the view that SOX is not a preferred means of assuring effective controls in the Company, and IUSA has been cited as the only ISA entity using that approach.

Particularly given the merger order's requirement with respect to SOX, it is therefore proper to question where ISA and IUSA are going in the future. The Company has acknowledged that it has not applied a "regulatory" versus a "financial" filter to its processes for determining where to change or reclassify key controls. We find the failure to add this perspective curious, given the source of the requirement that IUSA "continue to comply with the provisions" "as if it were still bound directly." We think it clear that the Commission intended concern about the accuracy and completeness of financial information to relate at least very substantially, if not predominantly, to producing confidence that it can rely upon such information for regulatory, as opposed to informed investment, decisions. Thus, consistency with industry experience in terms of investor interests is not the only relevant test. We would not expect that the Commission's concern was to "freeze" compliance at a pre-ISA point in time; we would equally expect, however, that substantial change be undertaken with knowledge of and concern for impacts on regulatory reliance on the information broadly encompassed by the merger condition.

6. Annual internal audit plans result from a structured risk assessment process that fully considers New York utility risks, and produces sufficient examination of utility costs.

IUSA, operating under a planning structure common to ISA subholding companies undertakes a reasonably well structured and comprehensive approach to the identification of risk and creation of a responsive audit plan. Internal Audit resources and the use of outside "co-sourcing" indicate an appropriate and stable level of resources. Internal Audit has carried out its work in accord with plans and under an appropriate level of reporting to the IUSA board audit committee.

7. Operations audits have not been a focus of IUSA, but comprehensive processes focused on business transformation and best practice institution have produced a strong focus on operations structures, resources, procedures, and processes.

There has not been a focus on the conduct of operations audits addressing New York utility operations. There has, however, been ongoing, comprehensive attention paid to methods and practices, as ISA seeks to introduce best practices to all of its subholding companies. IUSA has been an active participant in these processes recently, and is expected to continue doing so for some time.

8. Prior to two recent affiliates audits conducted after circumstances at National Grid focused attention to the issue, Internal Audit had not been conducting regular examinations of affiliate transactions. *(Recommendation #3)*

Liberty asked about affiliates audits conducted in the past five to seven years. The two cited by IUSA have both occurred since the middle of 2010, after the issue became a matter of scrutiny by the Commission at National Grid. We found no future planned audits of affiliate relationships or transactions. We believe that affiliate relationships and costs should form a regular part of the internal audit plans. The scope of the audits at IUSA seems to have been influenced directly by some of the issues involving National Grid (*e.g.*, expat employee costs). It is important to assure that a commitment to examining affiliate relationships and costs is driven by more than public attention to circumstances at other companies.

The second of these two audits found issues in a number of different areas. IUSA responded to a data request by stating that it does not have documents addressing the status of efforts to address them.[1] Best audit practice calls for structured means to follow and document progress in implementing audit recommendations, to assure that management response is timely and fully effective.

9. There exist overall an appropriate set of policies, procedures, requirements, reporting, and enforcement of standards of ethical behavior and conflict-of-interest.

IUSA has brought an appropriate structure and representative code to its addressing of ethics in its operations. There is sufficient communication of the importance of ethical behavior, and appropriate means for reporting of potential ethics violations.

10. The IUSA Code of Conduct treats affiliate relationships and transactions at too general a level. *(Recommendation #4)*

The Code talks about externally imposed standards that "may" exist and it describes employee obligations only in connection with complying with external standards. It is important that the

[1] Company comments to the draft of this report cited the institution of a more structured tracking mechanism following completion of Liberty's audit work.

message to employees reflect internal values and principles on the subject of assuring that utility operations and resources not subsidize affiliates or share resources and data inappropriately. Moreover, the code should reference specifically applicable requirements and standards (both internal and external), rather than leaving open the question of which ones may exist. An employee finished reading the IUSA code gains no sense that proper control of affiliate relationships and transactions comprises an important value, is left with no guidance about how or where IUSA (through internal and externally imposed rules, policies, and guidance) assures that those values will be assured, or mitigates the potential for and responds to violations. A reading of the code in fact leaves open whether there are any rules, policies, or guidance at all.

11. The lack of separation between legal ethics functions does not comport with our view of best practice. *(Recommendation #5)*

The role of chief ethics and compliance officer is fairly new; one result is a continuing debate about where and what organizational level it should be placed. Our view is that separation from the general counsel and the legal organization and placement at a high level are necessary to remove actual and apparent conflicts in role and to maximize effectiveness of internal efforts to prevent, mitigate, and respond to ethics and conflicts situations. We view the presence of affiliate operations in a utility structure (and the inherent risks of cross subsidization) to underscore the importance of the position generally and the separation we believe is appropriate.

We recognize that the separation of the roles is not universal, but neither is combination of the positions a dominant pattern. In preference to an extended discussion of the conflicts, appearance, and other underlying issues, we present below a partial list (from recent industry literature) of arguments that, while reasonably balanced, reflect generally the side of this question that we consider to be the better reasoned.

- http://www.rand.org/pubs/conf_proceedings/2009/RAND_CF258.pdf
- http://www.cmswire.com/cms/information-management/grc-the-evolution-chief-ethics-and-compliance-officer-role-011557.php
- http://www.europeanbusinessreview.com/?p=3633
- http://compliance.saiglobal.com/viewpoint/2011/02/factors-to-consider-in-compliance-reporting-structures/

F. Controls - Recommendations

2. Subject prior and future changes in SOX compliance structure, structure, responsibilities, procedures, practices, and components (*e.g.*, key controls) to a focused analysis of potential impacts on utility regulatory processes and proceedings. *(Conclusion #5)*

We found that there already exists a reasonably well structured and thoughtful process for SOX compliance changes. We found particularly that controls "de-keying" is preceded by securing the views of management, Internal Audit, and the outside accountants. It further appears that a consensus among them is effectively required. The change control process, as it concerns us here, therefore, is already in place. What is needed is a requirement that changes be preceded by an analysis of potential impact on regulatory processes and proceedings. For example, a change that may not appear damaging when one takes a consolidated view of financial materiality (e.g., a change in allocation of costs among affiliates that does not affect the consolidated bottom line) may have greater significance when determining whether costs go to Maine or to New York, to NYSEG or to RG&E, to gas or to electric, or to utility or to non-utility).

There have been many changes to date in the number of key controls. They should be reviewed for regulatory impact, and should require formal sign-off. Future changes in this aspect of SOX compliance or others should be similarly reviewed before they are made.

Given the nature of the SOX compliance process at IUSA, the involvement already existing for Internal Audit and the outside accountants, we do not expect material cost changes to result from implementation. The benefits will be increased assurance of accuracy and completeness in financial information relevant to regulatory processes and procedures. One cannot know whether the net change in costs to customers from such greater assurances will be positive or negative.

3. **Make examination of affiliate relationships and transactions a recurring element of Internal Audit's plans and provide for clear, timely documentation and reporting of progress in implementing recommendations.** *(Conclusion #8)*

Internal Audit has performed two recent audits of important aspects of affiliate relationships and transactions. If performed as part of a program that will include fairly regular reviews of this type (varying as appropriate to assure that all substantial risks of regulatory concern are addressed with reasonable frequency), such audits would typify the type of program we envision. It is not clear, however, that IUSA intends to continue them at this level of scope and depth.

Internal Audit should prepare (with such input from management as required relative to values and principles and for review and approval by the IUSA board audit committee) a policy document addressing:

- The Company's view of the values and principles applicable with respect to arm's-length dealing with and avoidance of cross subsidization of affiliates
- What are the principal risks to full adherence and conformity to applicable regulatory requirements, Company values and principles, Code-of-Conduct requirements, and other Company policies, procedures, and other guidance involving affiliate relationships and transactions
- How Internal Audit will craft and execute a programmatic approach to assuring that all substantial risks are sufficiently tested within an appropriate and defined time cycle.

This document should then guide annual audit plans accordingly, with affiliate relationships and transaction examinations forming a fairly regular component of those annual plans.

The benefits of implementing this recommendation will be improved assurances that affiliate relationships and transactions are being managed and executed at arm's-length and without undue risk of cross subsidization. There may be no incremental costs, should affiliates examinations displace other audit work. Should IUSA be unable to do so, we would expect the incremental costs to be no greater on an ongoing basis than those associated with a one-quarter time senior auditor.

4. **Incorporate into the IUSA Code of Conduct specific statements of IUSA values and principles regarding affiliate relationships and transactions, and summarize and make references to applicable policies, procedures, and guidance.** *(Conclusion #10)*

Well-designed codes make clear that assuring arm's-length dealing with and avoiding utility cross-subsidization of affiliates represents an important corporate priority, and one that derives not just from externally imposed requirements, but from a company's own values. IUSA should incorporate into its Code (and reinforce through regular, cyclical messages to employees from senior leadership) what its values are in this respect. The Code should also make clear at a summary level what requirements, policies, and procedures do (not "may") exist, whether derived from external requirements or internally generated. The Code should express expectations about employee behavior, consequences for violations, and procedures for reporting violations in a manner similar to that applicable to other forms of violations of ethical standards.

Implementation of this requirement should not add materially to the costs of already existing methods of communicating with employees about ethical values, standards, and expectations. The benefits of implementation will come in the form of providing employees with a clear sense of the importance of arms'-length dealing with and avoiding cross subsidization of affiliates.

5. **Make the reporting of the IUSA chief ethics and compliance lead organizationally separate from the general counsel's organization, establish a direct reporting organizational relationship to the IUSA CEO, and provide for regular and confidential reporting to the IUSA board's audit committee.** *(Conclusion #11)*

This change will better assure the independence of and organizational "clout" of the chief ethics position, which we consider to be consistent with best industry practice. We anticipate that moving the compliance director position to that of vice president would cost in the range of $100,000 additional per year.

G. Performance Measurement - Findings

1. General Approach

IUSA's approach to performance measurement applies targets driven downward from the top of the organization to the employee level, and integrates measurement against those targets with compensation decisions.

The goal is to use the corporate mission, goals, and objectives as a top-level starting point, down from which cascade a set of coordinated goals at subsidiary, business area, and individual levels. These top-level corporate starting points therefore produce, in the case of IUSA, both ISA-level and U.S.-level metrics. An IUSA employee's individual performance evaluation includes measures from the ISA to the individual level. Discretely quantified portions of annual incentive compensation (discussed in a following section) for participants in the Annual Incentive Program (AIP) depend on performance against largely quantified measures at all these levels.

IUSA generally establishes its cascading and integrated goals in the October through November time frame. For 2011, however, the process was not completed in a timely manner. Some organization and individual targets remained incomplete through at least the middle of 2011.

Employees therefore were working for much of the year without full understanding of how their performance for that year will be measured or how their incentive awards would be calculated.

The process flow for creating and measuring individual performance against targets is as follows:

- ISA develops corporate (parent and overall, bottom-line IUSA) goals
- ISA communicates goals to IUSA
- IUSA business leaders develop goals specific to their organizations, seeking alignment with corporate goals
- IUSA business leaders communicate business area goals and negotiate with employees who are AIP participants to develop individual targets aligned with business area goals
- Mid-year and year-end sessions between employees and supervisors to review and measure progress, and identify development opportunities.

The next table shows the targets regularly measured at the IUSA corporate level for 2011 for NYSEG and RG&E. Our review found them to be consistent with the general breadth and with the content of IUSA corporate plans. We also found more detailed business area goals to be consistent with them.

Activity	Benchmark	Company		Activity	Benchmark	Company	
		NYSEG	RG&E			NYSEG	RG&E
Cust. Satisfaction	Northeast Survey	Top 3	Top 3	Inventory Accuracy	Actual vs. SAP	95.0%	95.0%
Cust. Satisfaction	Contact Satisfaction	≥73%	≥83%	Item Availability	% of defined items	98.5%	98.5%
Cust. Satisfaction	Answered 30 secs.	≥63%	≥77%	Fleet Avail.	Time available	98.0%	98.0%
Cust. Complaints	/1,000 customers	≤1.0	≤1.8	O&M Ratio	Actual/plan	95.0%	95.0%
Meter Read	Read Access Rate	N/A	N/A	Cap. Spending	Committed/plan	100.0%	100.0%
Meter Read	Estimated Reads	≤6.1	≤6.0	Client Satis.	Survey results	≥7.5	≥7.5
Uncollectibles	Write-Offs	$15.1M	$15.2M	Desk Ans. Time	Ans. 30 secs.	≥85%	≥85%
Uncollectibles	Debtor Days	41	54	Desk Resolution	Rslvd. level 1	≥70%	≥70%
Interruptions	CAIDI	≤2.08	≤1.90	Systems avail.	% Availability	≥99.75%	≥99.75%
New Installations	Date promised	N/A	N/A	SAP response	Mins. On-line	≤200	≤200
Emergency Drill	Sched./ Complete	Annual	Annual	Nightly batches	Accurate/timely	≥98%	≥98%
NERC Cert.	Sched./ Complete	Annual	Annual	Print services	1day produce/mail	≥99%	≥99%
Black Start Drill	Sched./ Complete	Annual	Annual	Disaster plng.	1 Test/Center	Annual	Annual
Load Relief Drill	Sched./ Complete	Annual	Annual	Cust. Services	Ops. Expense	$ 73.1M	$ 32.1M
Maine #11 Drill	Sched./ Complete	N/A	N/A	Electric T & D	Ops. Expense	$ 134.3M	$ 26.9M
Leak Response	Less than 30 min.	.≥75%	.≥75%	Gas Distribution	Ops. Expense	$ 37.7M	$ 15.6M
Leak Response	Less than 45 min.	.≥90%	.≥90%	Eng./Asset Mgmt.	Ops. Expense	$ 59.6M	$ 22.4M
Leak Response	Less than 60 min.	.≥95%	.≥95%	General Services	Ops. Expense	$ 4.2M	$ 5.4M
Mains	Miles annually	≥24	≥24	IT	Ops. Expense	$22.1	$ 9.4M
Services	# annually	≥1,200	≥1,000	Business Transform.	Ops. Expense	$0.0	$ 0.0M
Leaks	Backlogs	<100	<200	Total	Ops. Expense	$331.0	$ 111.8M
Excavation Dam.	Overall/1k	≤2.00	≤2.00	Cust. Services	Empl.Safety	≤5.00	≤5.00
Excavation Dam.	Mismark/1k	≤0.50	≤0.50	Electric T & D	Empl.Safety	≤5.00	≤5.00
Excavation Dam.	Co. Crew/1k	≤0.20	≤0.20	Gas Dist.	Empl.Safety	≤5.00	≤5.00
Interruptions	SAIFI	≤1.20	≤0.9	Eng./Asset Mgmt.	Empl.Safety	≤5.00	≤5.00
Capital Spend	Annual Elec.	$176.2M	$171.5M	General Services	Empl.Safety	≤5.00	≤5.00
Capital Spend	Annual Gas	$43.2M	$34.4M	IT	Empl.Safety	≤5.00	≤5.00
Capital Spend	MPRP	N/A	N/A	Business Transform.	Empl.Safety	≤5.00	≤5.00
Capital Spend	AMI	N/A	N/A	Cust. Services	OpCo/Pres Mt.	Quarterly	Quarterly
Capital Spend	Total	$219.4M	$205.9M	Electric T & D	OpCo/Pres Mt	Quarterly	Quarterly
NERC/NPCC/ISO	Support Compliance	Ongoing	Ongoing	Gas Distribution	OpCo/Pres Mt	Quarterly	Quarterly
Vegetation Mgmt.	Spans	N/A	N/A	Eng./Asset Mgmt.	OpCo/Pres Mt	Quarterly	Quarterly
Vegetation Mgmt.	Miles	2,700	1,100	General Services	OpCo/Pres Mt	Quarterly	Quarterly
Vegetation Mgmt.	Annual Spend	$16.0M	$6.6M	IT	OpCo/Pres Mt	Quarterly	Quarterly
Inventory Turns	Total vs. Inventory	2.35	2.35	Business Transform.	OpCo/Pres Mt	Quarterly	Quarterly

2. Integration with Incentive Compensation

The Annual Incentive Plan (AIP) provides for a hierarchical structure by cascading objectives from the mission/strategic plans of the business including Iberdrola Group, Iberdrola Group Networks, Iberdrola USA, Business Area and Personal performance objectives. Directors and above participate in the AIP. Objectives continue to cascade down to employee's performance objectives. Employees below the Director level are eligible for the Group Incentive Plan (GIP) which similarly includes Iberdrola Group, Iberdrola Group Networks, Iberdrola USA and Business Area/Affiliate objectives. A GIP eligible employee's personal objectives also impact their overall incentive payout. Please note that the AIP/GIP objectives are not inclusive of all key performance measures across the business.

IUSA has established a broad and largely quantified set of performance metrics, and uses them in incentive awards, as shown below. The next table shows that 2010 performance essentially universally exceeded established targets. In all areas, actual costs ran significantly below budget, and in many cases by large gaps. There was not substantial stretching of the 2011 targets from their 2010 levels. IUSA did, however, add and change some of the areas measured since 2010.

O&M 2010 Budget to Actuals by Business Area			
Area	**Budget**	**Actual**	**Under**
Operations	$136,177,107	$118,961,000	13%
Eng & Asset Mgt	$66,473,787	$50,575,000	24%
Energy Supply	$4,462,448	$3,661,000	18%
Fossil/Hydro Ops	$7,123,559	$5,770,000	19%
Executive Administration	$61,785,683	$55,186,000	11%
Human Resources	$43,489,783	$27,276,000	37%
Rates & Regulatory	$6,872,842	$4,675,000	32%
General Services	$61,088,486	$51,182,741	16%
Transmission Services	$1,837,528	$1,205,000	34%
Average		***23%***	

Actual 2010 performance in all areas subject to objective, quantified measures was substantially better than targets, by the amounts shown below.

Customer Service

Metric	vs. Target	Metric	vs. Target	Metric	vs. Target
Arrears	5 percent	Write-offs	44 percent	Customer Satisfaction	9 percent
Answer speed	5 percent	Complaint Rate	292 percent	Estimated Reads	67 percent

Operations

Metric	vs. Target	Metric	vs. Target
Main/Service Replacement	8 percent	Odor Call Response	8 percent
Gas Damage Prevention	86 percent	Gas Leak Management	82 percent
Electric Reliability (CAIDI & SAIFI)	12 percent	Safety	19 percent

Energy Supply

Metric	vs. Target	Metric	vs. Target
Electric Supply	6 percent	Gas Cost Incentive Target	25 percent

Fossil/Hydro Operations

Metric	vs. Target	Metric	vs. Target	Metric	vs. Target
Allegheny Availability	4 percent	Hydro Flow Use	2 percent	Safety	16 percent

General Services

Metric	vs. Target	Metric	vs. Target
Fleet Availability	At Target	Critical Item Availability	1 percent
Inventory Turns	60 percent	Emergency Plan Testing	At target
Safety	19 percent		

The next tables show that reliability measures have not changed since at least 2006, while performance has overall exceeded them.

New York Electric Reliability Metrics (after exclusions)

Year	CAIDI			SAIDI		
	Actual	Goal	Δ	Actual	Goal	Δ
2011*	2.03	2.08	*	0.23	1.20	*
2010	1.98	2.08	5%	1.14	1.20	5%
2009	2.00	2.08	4%	1.08	1.20	10%
2008	2.08	2.08	0%	1.11	1.20	7%
2007	2.22	2.08	-7%	1.19	1.20	1%
2006	2.01	2.08	3%	1.11	1.20	7%

Year	CAIDI			SAIDI		
	Actual	Goal	Δ	Actual	Goal	Δ
2011*	1.30	1.90	*	0.26	0.90	*
2010	1.71	1.90	10%	0.71	0.90	21%
2009	1.80	1.90	5%	0.59	0.90	34%
2008	1.85	1.90	3%	0.78	0.90	13%
2007	1.73	1.90	9%	0.86	0.90	4%
2006	1.78	1.90	6%	0.79	0.90	12%

* Through May 6; Differential not meaningful
Better than Goal

The next table shows that safety performance has also steadily improved, moving to well below the goal, IUSA reports as becoming more aggressive each year, in order to assure steady safety improvement. The 2011 data is for a partial year and NYSEG and RG&E measures have been averaged to conform them to prior-year reporting.

Safety Metrics

Year	Index	Year	Index	Year	Index
2011	4.3	2009	3.5	2007	5.2
2010	4.2	2008	4.4	2006	6.3

Better than Current Target

The Company uses the recently established metrics from the rate case to measure gas performance. The next table shows these metrics. The following one shows performance reported to the Commission in recent years.

Where metrics have been established by the Commission (*e.g.*, in the last rate case, as shown in the following table), IUSA uses them without any adjustment for internal purposes. The succeeding table shows that actual performance has exceeded targets for some time in this area as well.

PSC Rate-Order Service Metrics

Metric	Value	
	NYSEG	RG&E
Replace leak-prone pipe (miles per year)	24	24
Replace leak-prone services (miles per year)	1,200	1,000
Leak management (Year-end leak backlog)	100	200

Excavation damage (damages/1,000 Tickets)	2.0	2.0
Damages due to mismarks (damages/1,000 Tickets)	0.5	0.5
Company, contractor damages (damages/1,000 Tickets)	0.2	0.2
Leak/odor call responses (percent in 30 minutes)	75%	75%
Leak/odor call responses (percent in 45 minutes)	90%	90%
Leak/odor call responses (percent in 60 minutes)	95%	95%

Gas Performance Measures Since 2005

Metric	**2005**		**2006**		**2007**		**2008**		**2009**		**2010**	
	NYS	**RGE**	**NYS**	**RGE**	**NYS**	**RGE**	**NYS**	**RGE**	**NYS**	**RGE**	**NYS**	**RGE**
Pipe replaced	8.28	16.24	15.67	15.69	15.37	15.67	15.51	15.17	20.56	21.21	21.01	23.12
Services replaced	2,169	1,225	2,093	1,278	1,952	1,309	2,083	1,125	2,220	2,042	2,104	2,087
Leak backlog			142		57		50		42	179	42	158
Excavation Damages		3.44	1.82	2.71	2.48	2.75	1.56	1.82	1.73	1.95	1.74	1.55
Mismark Damage			0.34		0.41		0.32		0.36	0.32	0.36	0.36
Crew damages									0.02	0.08	0.05	0.11
Leak response (30)	82%	95%	78%	93%	75%	92%	80%	92%	82%	92%	80%	91%
Leak response (45)	96%	99%	94%	99%	95%	99%	96%	%99	96%	99%	95%	98%
Leak response(60)	99%	100%	99%	100%	99%	100%	99%	%100	99%	100%	99%	99%

Better than PSC Target

The "2009 Gas Safety Performance Measures Report by the Safety Section of the NY Department of Public Service's Office of Electric, Gas & Water (Case 10-G-0225)" reported substantial improvement over the preceding seven years by gas distribution utilities across the state. It included the following sets of comparative New York gas utility data.

The report has shown consistently very strong NYSEG and RG&E damage-avoidance performance across the period studied. NYSEG and RG&E experienced increases in damages in some recent years (2007 and 2009), but their rates remained very low, even 2007 and 2009, when compared to other New York gas LDCs. The two IUSA LDCs are among the four New York LDCs to have met the 30-minute all response time goal in each year since 2003. All 11 New York LDCs met this goal in 2008 and 2009. Leak backlogs declined by 75 percent statewide in 2009, with both NYSEG (83 percent), and RG&E (78 percent) exceeding this rate of reduction. Both companies total number of backlogged leaks remained at the low end of the range of New York experience throughout the period. NYSEG and RG&E were the only LDCs receiving no staff recommendations for self-assessments to identify high rates (*i.e.*, possible performance issues) in any of the areas studied.

3. Business Area Metrics

IUSA also used a series of business area metrics to measure performance. They are consistent with and cascade downward from the metrics routinely reported at the corporate "scorecard" level.

a. Energy Supply

The next charts show these quantified targets, and demonstrate that the companies routinely exceed them, as is typical in other areas. The most recent Commission rate order established the basis for the natural gas cost incentive mechanism (NGIM) metric. It shares between the utilities and customers those dollar savings achieved through capacity releases and off-system sales.

Electric Dollar per MWh

Year	NYSEG		RG&E	
	Target	*Actual*	*Target*	*Actual*
2006	$66.27	$65.75	$46.74	$44.05
2007	$73.26	$72.80	$48.59	$46.30
2008	$78.03	$75.07	$55.14	$54.91
2009	$69.68	$57.44	$55.53	$54.01
2010	$50.82	$46.81	$45.83	$44.71

Electric Load Forecast Error

NYSEG & RG&E Combined	*Target*	*Actual*
2006	3.50%	2.78%
2007	3.50%	2.83%
2008	3.50%	2.98%
2009	3.50%	2.79%
2010	3.50%	2.82%

Year	NYSEG				RG&E			
	Residential		*Non-Residential*		*Residential*		*Non-Residential*	
	Portfolio	*Market*	*Portfolio*	*Market*	*Portfolio*	*Market*	*Portfolio*	*Market*
2008	11.00%	18.00%	15.00%	19.00%	19.00%	19.00%	17.00%	19.00%
2009	22.00%	22.00%	21.00%	21.00%	16.00%	24.00%	14.00%	24.00%
2010	10.00%	15.00%	11.00%	16.00%	15.00%	16.00%	13.00%	16.00%

Target is portfolio ≥ 2% below market

Better than Goal

Natural Gas Cost Incentive Mechanism

Year	*NYSEG*		*RG&E*	
	Target	*Actual*	*Target*	*Actual*
2006	$887,210	$1,484,100	$501,810	$955,600
2007	$903,000	$1,486,050	$555,000	$636,840
2008	$728,000	$1,425,980	$416,000	$1,231,780
2009	$728,000	$910,280	$206,000	$163,240
NYSEG and RG&E Combined Starting with 2010				
2010	$935,000	$1,173,454		
2011	$875,000	$947,021		

Goal is actual greater than target

Better than Goal

NYSEG and RG&E have also used varying unquantified metrics in recent years, as the next table summarizes.

2007		
PSC hedge reporting requirements	NYISO final bill process	NERC/ERO standards
2008		
Gas Transportation Ops Procedures	PSC hedging requirements	Gas portfolio report
	Capacity turnback strategy	
2009		
Local gas interconnects/ pricing	2010 commodity programs strategy	Electric commodity hedge analysis

2010		
PSC Commodity Rate Orders	PSC delivery rate order	Gas Portfolio Report
Capacity turnback strategy	Energy supply strategic plan	

b. CFO Organization

The IUSA CFO organization has established targets, and performed monthly tracking in two areas specific to its operations:

- Purchasing
  - Purchasing employees as percent of total employees
  - Savings dollars per budget dollar
  - "Supplier Diversity" purchase value divided by total spend
  - Green-house gas reductions versus target
  - Average days to turn non-stock purchase requisitions into purchase orders
- Accounts Payable
  - Accounts Payable Cost
  - AP Invoices Processed-Manual
  - AP Invoices Processed-Automatic
  - AP Cost per Invoice Processed
  - Average Days in AP-PO Invoices
  - AP Blocked Invoices

c. Human Resources

Human Resources regularly uses the following metrics to measure performance:

Payroll processing-target date	Paycheck accuracy	Human resources-accuracy
Payroll service staff resolution time	HR staff resolution time	Business partner service rating
Surveys sent/returned Total O&M	Payroll process (SAP)	HR accuracy prior to audit
Payroll accuracy prior to audit	Payroll process execution accuracy	Off cycle check accuracy

d. Information Technology

IT regularly applies the following metrics to its operations:

Critical Systems Availability	SAP On-line Performance	Service Desk Answer Time
Service Desk Resolution Rate	End User Satisfaction	Business Owner Satisfaction
Nightly Batch Processing	Same Day Print Services	Disaster/Emergency Planning

General Services regularly applies the following metrics to its operations:

Inventory Turns	Critical Item Availability	Fleet Expenses
Fleet Availability	Facility Management and Real Estate (under development)	

4. Benchmarking

IUSA reports the following benchmarking studies since 2007:

- Shared Service Roundtable (a utility association): USS (Accounting) External Benchmarking (February 2009)
- McKinsey & Co.: Assessing the Improvement Opportunity at Energy East (January 14, 2010)
- IUSA: Network Economic Benchmarking Analysis (March 2010)

- IUSA: Business Transformation: Final Report Out – Accelerating Operational Performance Improvement (December2010)

The next table lists the measurement bases that IUSA uses for corporate and industry comparisons on the basis of employees, customers, and distributed energy.

Employees	Total Capacity	Service Area	Underground Outages
Total Lines	New Lines	Total Outages	Other Outages
OH Lines	New Transformers	Overhead Outages	Third Party Outages
UG Lines	New Connections	Distributed Energy	Calls to Call Center
Total Transformers	New Capacity		

Liberty asked that IUSA identify any group specifically focused on NYSEG/RG&E performance measurement and enhancement. The answer referred to the existence of the AIP and GIP, but identified no such group.

5. Regular Performance Reports

IUSA responded to Liberty's request for reports addressing financial, service, staffing, and other operations by providing the following:

- Reports to senior U.S. management
  - SLM [Service Level Measures] Scorecard
  - IUSA Operations SLMs
  - Regulatory Performance Measures
  - Business Transformation Update
  - Human Resources Weekly Report
  - Performance Management Report (monthly income statement, energy delivered, customer numbers, return on equity,
- Reports to IUSA board and senior ISA management (Spain)
  - Performance Management Report
  - IUSA Weekly Update (summary of company news items)
  - Monthly Highlight Report (four-page bullet list of industry and company news items; one-line project updates)
  - EBITDA update
  - Business Transformation Update (one slide summarizing savings)
  - Monthly Earnings Summary (nine-page slide deck)

a. SLM Scorecard

IUSA has developed for use in 2011 an *SLM Scorecard*. It came as part of recent organization changes that created the IUSA Chief Operating Officer organization and the transition to "matrix management." IUSA did not previously use such an approach, relying through 2010 on budget variance reporting as the primary measures of performance. IUSA has stated that management of T&D activities at the operating company level before the reorganization meant that service-level scorecards were not required.

The Scorecard's measures derive from an *Iberdrola USA Operations Service Level Measures* 2011 document that describes the services provided by operations (termed IUO) to the three operating U.S. utilities. The document describes the metrics used for measurement of each service provided, and provides for regular reporting (monthly, quarterly, annual) against those metrics. Those areas of service comprise:

Customer Service	*Electric Distribution*	*Gas Distribution*
Engineering/Asset Management	*General Services*	*Information Technology*

IUO and the operating utilities must jointly approve the metrics, which must, at a minimum, address all targets established by state regulatory authorities.

b. Regulatory Metrics Reporting

IUSA issues regular monthly reports for all "regulatory" metrics. The report compares year-to-date quantitative status or progress against each target established under regulatory authority, projects status at year-end, and discusses recovery plans for metrics in jeopardy of not being met.

c. Business Transformation Reporting

IUSA reported the savings resulting from its business transformation process at the end of 2010. The next illustration, which is confidential, depicts that report.

[redacted]

IUSA issues these reports at the end of what it terms "waves." Senior management reports that the process has now moved past addressing what it described as "low hanging fruit," with succeeding waves to address more substantive process and infrastructure (*e.g.* systems and infrastructure development).

Prior to the formation of the matrix organization the majority of the operational activates were managed functionally by the Operating Companies themselves. For example all T&D activities were managed within the NY Operating Companies including CADI, Annual Drills, and NERC certification. This organization design did not dictate the need for service level scorecards.

Performance against budgets comprised the primary Service Measure prior to the development of the aforementioned SLM scorecard.

H. Performance Measurement - Conclusions

12. IUSA regularly establishes, monitors performance against, reviews, and uses comprehensive and sufficiently quantified performance goals and targets at a high level.

IUSA uses its system of high-level corporate and unit goals to establish a series of complementary metrics that the Company regularly reinforces the importance of those goals and against which it regularly and comprehensively measures performance. IUSA does well in seeking to make its metrics objectively measurable, supporting clear measures of progress, and enabling a strong tie to individual performance measurement and compensation.

Metrics correspond to specific, measurable goals and objectives at lower levels of the organization. We examined how goals and objectives cascade downward through lower organization levels. We also examined the specific metrics used at the work-group level and for a sample of executives, managers, and directors at the individual level (as part of performance management). We found a good level correspondence to differing and narrowing responsibilities moving down from the IUSA level, through the department or functional level, and down to the individual level. Searching downward through the "chains of command" disclosed that group and individual goals and the metrics used to address them bore a reasonably close relationship to the discrete activities necessary for accomplishing detailed goals and service-affecting processes. We have found this form of "linkage" commonly to be a weak one in our past experience. IUSA, however, demonstrates a sound recognition of making its goals and objectives and its means of measuring them "speak" to each level involved in achieving them.

Measurements applied to individual departments, work groups, activities, and individuals should conform to their responsibilities and accountabilities.

13. IUSA employs a comprehensive set of metrics and key performance indicators tied to goals and targets addressing cost and service quality.

IUSA has designed metrics that correspond to all of the measures addressed by Commission requirements. Those metrics correspond to goals that embody Commission service-quality and expenditure (or installation or repair) requirements. The metrics cascade down to the detailed functional or department level, enabling IUSA to measure directly the performance of groups responsible for the activities that drive success or failure in meeting service-quality goals.

IUSA also adopts at the corporate and detailed levels cost performance goals and objectives and supporting, objective measures, which are subject to regular measurement.

There is adequate attention to producing measurement of performance. To the extent that performance results drive compensation, there is also a review of the accuracy of measurements.

14. IUSA measurements adequately measure cost and service quality at the "output" level, but have yet to produce comprehensive measures of "inputs." *(Recommendation #6)*

The preceding two conclusions confirm relative strengths in IUSA's performance management approach and processes. In this particular respect, we do find a gap, but note that it is a somewhat common one in our experience. We have over time become more focused on the issue because, as we have seen an increasing focus on financial targets and performance, we have observed a less "operations-centric" view generally in the industry. We would have been more inclined to take on faith some years ago that management remained "in touch" with the fundamentals driving operational results (or, perhaps better said, had them "ingrained" in its thinking). Recent experience, however, teaches us that bringing attention to those fundamentals in tangible, objective ways has become more important.

This issue receives substantial attention in Chapter XIII, which focuses on work management at the detailed level. At the IUSA corporate level, we found appropriate capital and O&M expense targets and measurements at the overall IUSA level and for each major department or function. However, as Chapter XIII describes when addressing the details of work management, we also found here a lack of measurements designed to assure that apparently strong cost performance is not coming at the expense of weak production levels. Performance against budgets, all else equal, should only be considered strong when expected numbers of work units are actually achieved. Executive management and the board need to receive information that allows real-time assessment of actual work units performed and the unit rates (*i.e.*, productivity) underlying that performance. IUSA does monitor expenditures at the project level for major projects, but senior management acknowledged that measures are largely output-based (*e.g.*, actual versus budgeted total costs), and not input-based (*e.g.*, total units produced and unit costs of producing them versus the expectations underlying budgets). General Services stands as an exception to this general rule. Other executives have observed that the completion of efforts to introduce work management system enhancements (also addressed in Chapter XIII) will enable development of budgets on the basis of and measurement of performance against input measures.

15. External and internal benchmarking of performance has not strongly informed IUSA performance management. *(Recommendation #7)*

We begin by observing that IUSA has been engaged in comprehensive efforts to seek out best practices from among the ISA network companies, operating primarily in Europe and Scotland. We have no criticism of that engagement. Chapter II did, however note that ISA focused too strongly on its other operations in driving IUSA to substantial staffing reductions over time.

We refer here to benchmarking with other U.S. utility operations and to the use of comparative performance data within the IUSA utility footprint to identify internal performance leaders and laggers.

With respect to external benchmarks involving U.S. peers, we found early in the audit that leadership of the Business Transformation organization was interested in developing a comprehensive program of benchmarking key operations metrics. We had actually scheduled a session to share thoughts and ideas on the subject with that leadership; that meeting had the support of senior IUSA executive management. Upon arriving at the meeting, however, that leadership was not present; instead, IUSA's principal spokesperson about operations benchmarking was a lead regulatory person, whose purpose was not to discuss how benchmarking could be done effectively, but to criticize a discussion document he considered (incorrectly) to reflect Liberty's views of how IUSA performance compared with the industry and what conclusions to draw therefrom.

There has been a change in leadership in the Business Transformation organization (to fill a vacancy created by the return to ISA operations in Europe of an expat serving on IUSA's executive management team). As noted in Chapter XIII, we were unable to find any (outside the area of executive and management compensation, and perhaps Customer Service) industry benchmarking groups used by IUSA.

The lack of substantial operations benchmarking with U.S. peers, the recent change in leadership in the Business Transformation organization, and the impression from the benchmarking meeting (that went awry from our perspective) that benchmarking may be viewed more as a threat than an opportunity leads us to conclude that IUSA has not especially endorsed the value of comparing itself to its U.S. peers. That would be of concern in any event. Two factors heighten the concern here:

- That ISA used benchmarking with Spanish and Scottish performance to drive large staffing reductions
- That current efforts to identify best practices appear to be in very major part of a search for what is best within ISA globally.

Internal operations benchmarking is also not a strong focus. IUSA operates across a wide footprint, in many different types of serving areas, under a variety of work methods, and under many different sources of direct supervision. It can be expected to have:

- Stronger and weaker performers
- Comparatively weaker performers from a raw results perspective who may be performing quite well if their unique challenges are greater than those faced by groups more fortuitously situated
- Methods applied in one place that might improve performance if followed in other regions
- Areas where the same amount of additional or reduced spend might produce materially larger changes in results
- People who can be motivated by constructive comparisons ("friendly competition") among groups operating across the serving regions.

Leveraging these factors requires effective production and productivity information. Chapter XIII (and at a different level, preceding portions of this chapter) address the lack of such information at IUSA. That lack impairs the ability to take advantage of internal benchmarking at robust levels.

16. The IUSA board examines budget performance and performance against some high-level measures and approves compensation measures, but does so at a level that we consider comparatively very general. *(See generally the Governance Recommendations of Chapter II).*

The IUSA board in one case did not even approve the capital budget until well into the year in which it applied and it has not been highly engaged in IUSA executive compensation. It has routinely been advised about budget performance and it has approved the U.S. measures that apply to executive compensation. It also routinely receives information about the measures arising from regulatory processes, and has discussed plans to address gaps in performance relative to those measures.

Its level of review of objective measures of performance against established targets is not a strength when compared with other boards, but we view that more as a function of the issues already addressed in Chapter II, compounded by significant changes in membership over its relatively short history.

I. Performance Measurement – Recommendations

6. Develop a series input-based metrics that will permit more robust assessment of cost performance by measuring it against work units accomplished and the productivity achieved in accomplishing those units. *(Conclusion #14)*

Chapter XIII discusses work management comprehensively. Implementing its recommendations provide the necessary foundation for what is at issue here; *i.e.*, bringing greater executive management and IUSA board visibility on what underlies cost performance through clear, objective measures of work performance and work performed. A robust assessment of cost performance cannot take place without examining what work was performed for that cost. Moreover, focusing overly on output, or lagging measures, such as response times, outage duration and frequency, and leak rates, gives root causes too much time to take hold before they are addressed. Literally speaking, those consequences are not a function of the dollars spent on them, but on the activities undertaken to address them (inspections, repairs, trim cycles, calls answered per hour, hours per activity, for example). Without knowledge of what assumptions about these activities underlie budgets, about the levels at which activities are actually being performed, and at what levels of productivity these activities are being performed, company leadership does not have the data to assess what of today's activities are driving performance degradations that may not show up for a number of years later. More immediately, to the extent that performance metrics drive (as they should) performance evaluations and rewards, focusing on cost without considering work performed can send messages and induce suboptimal behaviors.

Therefore, as IUSA focuses on completing the installation of enhancements to its work management system, and as it implements the recommendations about cost and work management identified in Chapter XIII, senior executive leadership needs to identify for each department or major function how to incorporate metrics addressing the key work units and unit rates that drive costs. Only then can it measure cost performance in a sufficiently robust way (*i.e.*, by looking at more than variances from budgets).

We do not expect significant costs incremental to those required to address the recommendations of Chapter XIII. The benefits too will be similar. The particular value added at this level will be the gain in senior leadership's insight into and therefore ability to address much more promptly and effectively the root causes underlying the performance output measures that IUSA already addresses comprehensively with goals, objectives, and performance metrics.

7. **Establish a formal program applying a robust mix of external and internal benchmarks.** *(Conclusion #15)*

Prior to the change in leadership of the Business Transformation organization, it appeared that there was an intention to expand external benchmarking with U.S. peers. IUSA should reconfirm its intention to do so, communicate to leadership throughout the organization the firm value that benchmarking offers an operations-improvement opportunity and not a regulatory "threat." Within six months, IUSA should survey industry peers to select a group of benchmarking service and information providers who will provide credible information across the range of operations metrics that drive key functions, activities, and (particularly) costs. IUSA should take advantage of such services as it then develops and refines its own efforts to generate costs and methods/practices information in a way that will allow it to compare its operations with U.S. peers.

We consider it urgent that IUSA expedite this activity, given what we view as an over-focus on ISA methods, practices, resources, and costs. Not only should IUSA's search for best practices be strongly informed by what similar companies have done, but it should recognize that the U.S. industry offers particularly fertile ground for improvement opportunity identification. To some extent IUSA already does so; we consider, for example, General Services to be a comparatively strong IUSA performer in taking advantage of collective experience in this country. In making this recommendation, we do not intend to suggest that ISA's collective search for best practices across its multi-continent footprint are misdirected. However, we do think that they can be better informed by greater attention to experience in environments with a large "E" (as in climate and vegetation) and with a small "e" (as in regulatory, labor, and other social-economic-political dimensions).

We also recommend a similar plan for using improved production and productivity information to construct a program for using internal information (more particularly variations in that information across different parts of IUSA's operating footprint) to benchmark costs and methods/practices. We view this plan and its execution as a logical outgrowth of efforts that IUSA is already undertaking to enhance its systems for producing and its use of such data for work and resource planning, budgeting, and performance measurement. Chapter XIII discusses those efforts and future uses.

External benchmarking will involve fairly small incremental outside costs; we would anticipate an amount in the range of $250k as appropriate. Already existing positions identified in the organization charts of the Business Transformation organization would appear to have the capability to address internal efforts to gather additional information about U.S. peers (in the immediate term) and to use the data that enhancements in gathering and using internal production and productivity information will allow.

Implementing this recommendation will help assure the benefits that Chapter XIII identifies, and will provide for more effective top management and board oversight.

J. Compensation – Findings

We address compensation here as a central element in how a utility (or any business enterprise relying upon large numbers of employees) assures performance in accord with plans, goals, and objectives. Individuals may take positions in large measure to secure what compensation allows them in terms of their individual goals; companies worry about compensation because it allows them to attract, retain, and incent the kinds of people they need to carry out corporate missions and goals. Our focus particularly fell upon incentive compensation for senior management and executives, which prevailing thinking says should align very directly and substantially with goals, objectives, and tangible measures of success.

1. Overall Compensation Program Goals and Structure

ISA compensates senior executives under a policy titled the "Senior Management Compensation Policy of Iberdrola, S.A." The executives to which it applies include direct reports to the ISA board, its chairman, and its CEO and to any other person declared by the ISA board to be a "Senior Manager." IUSA personnel participate in the IUSA-specific program, not the ISA program. The ISA program, however, generally guides the design of the IUSA program. The ISA program provides, as is common in the U.S. industry for a combination of three principal elements; *i.e.*, base pay, annual incentives, and long-term incentives. IUSA, continuing a practice followed during the Energy East tenure, generally reviews base salary on an 18-month, rather than annual basis. Annual and long-term incentive components apply annually.

A documented set of objectives establish the key elements of the IUSA compensation program for U.S. senior management and executive personnel. Those objectives typify those Liberty has seen elsewhere. A 25-page *Pay Administration Guidelines* document details these program elements, which consist of:

- Structured job analysis reflected in standard job descriptions
- Market pricing employing marketplace data gathering
- Objective job evaluations
- Assignment of jobs to pay grades based on market data and business considerations
- Pay structure competitive with other organizations in the same labor markets
- Individual performance management under objective, quantifiable, consistent evaluations
- Variable cash compensation based on achievement of company and individual objectives
- Policies ensuring consistent program application.

IUSA applies a commonly adopted objective of targeting base pay and total cash compensation at the 50th percentile of markets where it competes for employees. IUSA uses a 10-grade position structure, which employs representative features:

- Sufficiently large gaps between the 10 grades
- Progressions through levels (termed "zones") from "learning" through "highly experienced"
- A reasonably broad range of compensation around the middle zone of the three (termed "competitive")
- A sufficiently sizeable spread between minimum and maximum pay.

The IUSA design leaves significant room for reflecting performance differentials in base pay. IUSA has established somewhat different compensation levels by geographic region for its U.S. operations. The zones consist of three distinct New York regions and a separate one for Maine. IUSA determines the pay differentials applicable to its different work locations with assistance from a leading compensation and benefits firm, most recently in May of this year.

IUSA uses a target of 10 to 55 percent of base pay for annual incentives, and limits individual payments to a maximum two times the individual's target. The IUSA long-term incentives through 2010 took the form of "phantom stock" whose value equaled that of ISA shares. IUSA changed the form of long-term incentives in 2011.Three Spain-based executives operate as part of the IUSA organization. All work to objectives set by and subject to the incentive compensation programs of IUSA.

2. IUSA Annual Incentive Program

a. AIP Program Description

A separate IUSA annual cash incentive plan, administered by the IUSA board of directors, covers IUSA executives and other "key employees." IUSA terms this program its Annual Incentive Plan ("AIP"). The IUSA Chairman (a senior ISA executive based in Spain) has the power to identify such key employees, which generally consist of executives and the first level below executives (generally termed "Directors").

The AIP establishes target bonuses as a percentage of base salary. The 2011 target and maximum incentive level percentages for 2011 for the AIP are shown in the next table. The 2011 program gives the IUSA board the power to provide a percentage of the incentive awards in the form of ISA stock.

Group	Target	Max	Group	Target	Max	Group	Target	Max
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			

The AIP divides these targets into categories (summing to 100 percent for each of the different levels of participants, who range from directors through vice presidents, to the CEO of IUSA. The next table shows the 2009 and 2010 weightings by area for the two basic employee groups covered by the plan.

Participants	ISA Group	IUSA	Business Area	Personal	Total
Executive Team	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Senior Managers and Directors	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Directors	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The AIP for IUSA participants was set to change for 2011, with the addition of objectives for another group; *i.e.*, Networks. The addition of Networks reflected the global restructuring of ISA operations to establish networks and liberalized groups. For some employees, the category added is termed "Corporate Function," rather than "Networks." The program for 2011 requires minimum (labeled "Satisfactory") performance in each of the now five categories for any AIP payments to occur. The next chart shows the 2011 weightings by objective areas for each participating employee class. The details of the program remained unfinalized at least through the middle of 2011. Therefore, the targets that incent and measure the performance of covered executives, senior managers, and directors did not exist in measurable form during much of the time period to which they applied.

Group	ISA Group	ISA Networks[1]	IUSA	Business Area	Personal	Total
CEO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Senior Executives[2]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Vice Presidents[3]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
COO Reports	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
All Others	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] or Corporate Function
[2] COO, VP Operations, NY and Maine Presidents
[3] HR, Finance, Regulatory, General Counsel

b. AIP Target Categories

The portion of AIP targets (like the overall percentage of base salary covered) also change for each of the participating AIP groups. The AIP categories and weightings for 2010 were:

- Iberdrola Group: 20 percent for directors to 50 percent for IUSA's CEO
- Iberdrola USA: 20 percent for directors to 40 percent for IUSA's CEO
- Business Area in which the participant works: 30 percent for all AIP participants
- Personal objectives tailored to each individual participant: 30 percent for directors to 10 percent for IUSA's CEO.

The recent creation of the Iberdrola Networks Group was intended to produce new categories for 2011. Many of the IUSA work groups were to be subject to newly created Networks Group goals. Others, who serve in support functions, were to be covered by separate Corporate Function objectives. The next table identifies those IUSA organizations intended to have Networks or Corporate Functions objectives for 2011.

Networks		**Corporate Function**
Office of the CEO	*Engineering & Asset Mgmt.*	*General Services*
Electric T&D	*NY President's Office*	*Information Technology*
Gas Operations	*Maine President's Office*	*Finance & Control*
Customer Service	*Business Transformation*	*Human Resources*

By the third quarter of 2011, ISA had failed to finalize the Networks Group goals, and had made less progress on Corporate Functions goals. The latter were eventually abandoned entirely, and will not be employed for 2012. Therefore, senior IUSA employees spent much of 2011 not knowing the full range of measures that would affect their annual incentive compensation. Liberty observed that senior Spanish executives (the source of Networks and Corporate Functions goals) were not clear on their impact on U.S. incentive compensation for 2011.

c. AIP Payment "Triggers"

Some of the categories of objectives operate as triggers; *i.e.*, no AIP payouts to an individual occur if performance for the year does not reach the trigger level for that category. The Iberdrola Group (ISA-wide) and the Iberdrola USA (and Network/Corporate Function targets planned starting with 2011) were to operate as triggers for all IUSA AIP participants. Failure to meet that threshold bars even AIP payments for meeting business area and personal targets. Moreover, the business area category operates as a trigger for all participants in that business area. The way that this "trigger" works is that payouts are 0 percent of what can be earned if performance is not at least equal to 80 percent (the "threshold" or "satisfactory") of the target. On the other hand, if performance is better than target, payments can rise as high as 200 percent of the value assigned to that category, should performance reach specified, superior levels.

d. AIP Target Approvals

The ISA board of directors sets the Iberdrola Group and Group Networks targets, using the ISA Group's approved business strategy as a guide. The IUSA board of directors approves the IUSA targets. The IUSA CEO and his business area leaders establish the IUSA business area targets. Participants and their managers negotiate their personal targets. ISA-level executives review all IUSA business area and personal targets before IUSA board approval. Internal Audit reviews all targets to verify their measurability. AIP target approvals vary, depending on the nature of the category and the level of the participant. The next table summarizes 2010 approval authorities.

Area	Goals Responsibilities		
	Set	**Review**	**Approve**
Group (ISA)	ISA President	ISA Board Nom & Comp Comm.	ISA Board
Company (IUSA)	IUSA Chairman	ISA Board Nom & Comp Comm.	IUSA Board
Business Area: Senior Team	Senior Team Executive	IUSA Chairman ISA Corporate Services Director	IUSA Board
Business Area: Others.	Peron Reporting To	IUSA Chairman ISA Corporate Services Director	IUSA Board
Personal	Not Listed		

The AIP documentation did not address establishment, review, and approval authorities for personal objectives. When asked about them, IUSA reported an intent to update the AIP guidance document as follows:

- Relating such objectives to the personal functions and responsibilities (but not development) of each participant
- Requiring at least two personal objectives for Senior Team (the new term for Senior Executive in the updated document) members and three for the next lower category of participant; *i.e.*, Senior Managers
- CEO recommends for IUSA board of director approval the personal objectives of his direct reports (*i.e.*, the Senior Team members)
- Senior Team members establish, upon CEO approval, Senior Manager personal objectives through individual negotiation.

Authority for the establishment of objectives by area changed somewhat for 2011:

- ISA Group: Approved by the ISA board of directors
- Networks: ISA Operating Committee

- IUSA: Proposed by the CEO and approved by the IUSA board of directors, ensuring alignment with ISA Group objectives
- Business Area: Proposed by the CEO and approved by the IUSA board of directors
- Personal:
  - For each Senior Team member (*i.e.*, direct report to the CEO/COO): established on recommendation of the CEO and approved by the IUSA board of directors
  - Other senior managers: established by the Senior Team members in conjunction with each of their direct reports; approved by the CEO.

e. Measurement of Performance versus AIP Targets

There are controls over the measurement of performance versus the AIP objectives. IUSA Human Resources gathers data for use in measuring IUSA, IUSA business area and personal objectives. IUSA Internal Audit reviews the documentation, and verifies the ratings. ISA Human Resources reviews those ratings, after which the IUSA board must approve them. ISA determines and pays bonuses for expats assigned to the U.S. ISA then charges IUSA the costs.

3. 2011 Group Incentive Plan

ISA operates a group incentive plan to cover those non-union employees who do not qualify for AIP participation. The 2011 program, documented by the "Remuneration Policy Group Incentive Plan for Non-Union Employees," provides for payment of a percentage of a Target Bonus amount (a percentage of base salary determined for each pay grade) for each Business Area. It ties to achievement of three sets of objectives:

- ISA Group and sub-group (*e.g.*, Networks): approved by the ISA board of directors
- IUSA: established and approved by the IUSA board of directors
- Business area: divided by direct reports to the CEO or COO and established by the IUSA board of directors on recommendation of the IUSA CEO.

Minimum performance targets for each of these three objectives areas must be met for bonuses to be paid. The program sets targets for two groups of employees, as the next table depicts.

Utilities			Non-Utilities		
Pay Grade	**Target**	**Max**	**Pay Grade**	**Target**	**Max**
6 and below	[redacted]	[redacted]	6 and below	[redacted]	[redacted]
7 and above	[redacted]	[redacted]	7 and above	[redacted]	[redacted]

IUSA explained the different target percentages for utility versus non-utility employees as resulting from the lesser contribution that the non-utility entities make to overall IUSA results, as compared with NYSEG and RG&E. The Maine and New Hampshire Gas Companies have slightly lower targets. Each objective set forms a quantified portion of the total target amount.

The scoring system for these incentives uses individual employee performance ratings to link an employee's payment and performance rating. The lowest rating calls for no bonus, the highest rating calls for a payment of 160 percent of an individual's target percentage.

4. Long-Term Incentive Plan

A Performance Share Plan (PSP) has served to fill the long-term component of IUSA's incentive compensation program. The PSP has used uses ISA stock as its basis and it uses long-term ISA performance as the reward basis to link employee motivations with overall Company performance. IUSA has generally applied a vesting period, with the potential for acceleration upon achievement of targeted levels of total shareholder return or return on equity. Participants have received, upon vesting, a cash payment that reflects share value at that date, plus dividends across the vesting period. ISA Human Resources reviews candidates nominated by IUSA management for participation, after which the IUSA board of directors must approve the participant list. The board has wide discretion in determining the value and conditions of these awards, applying its judgment about participants' present and future contributions, among other factors.

IUSA replaced the PSP with a Strategic Bonus Plan, beginning with 2011. The goal in making this change was to align long-term IUSA incentives with the global Iberdrola SA executive long-term incentive program. The target bonus under this new plan is expected to be expressed as a percentage of base pay plus the prior year's AIP award. The total award can be up to 200 percent of the target. Achievement of identified plan objectives will determine payouts. The objectives used in the most-recent recent ISA version of this plan were: net profit, total shareholder return, and maintenance of an "A" credit rating. A three-year measurement period will be used, with payouts occurring ratably over the succeeding three years. This approach requires executives to remain employed for three years following any three-year measurement period, in order to receive full payment for awards applicable to that measurement period. Payouts take the form of ISA shares and cash in an amount equal to estimated withholding taxes.

5. STAR Program

IUSA also conducts a "STAR" (**S**pontaneous, **T**angible, **A**chievement of **R**esults) Recognition Program, which provides for awards recognizing an individual contribution beyond normal expectations to expense management, margin enhancement, or improved customer satisfaction. IUSA has made 27 STAR awards since 2009. They totaled about $54,000, and ranged in value from $1,000 to $7,840. Storm work, capital expenditures, and the recent NYPSC rate case comprised the three categories (in order) making up the vast majority of the awards.

6. Benchmarking of Compensation

a. Peer Groups

IUSA measures competitiveness at the 50th percentile with the use of an energy-services sector peer group for energy-industry specific positions and with a general-services sector peer group for positions whose responsibilities are not unique to the energy industry. The IUSA *Pay Administration Guidelines* indicate that energy industry peers define the median for operations positions, while a broader group (which still includes the energy industry) is used for non-operations positions (citing accounting, IT, and legal as examples). This distinction recognizes the broader talent pool from which the latter types of employees come. The next table shows the peer-group members used for the most recent (2010) benchmarking of compensation. The highlighted members comprise those entities that, like IUSA, focus particularly on electricity and gas distribution operations.

AEI Services	***Black Hills***	***DTE***	***Entergy***	Kinder Morgan	***NRG***	Reliant
AGLR	***CenterPoint***	***Duke***	Ferrellgas	Midland Cogen.	***PG&E***	***SCANA***
Allegheny	***Cleco***	Dynegy	First Solar	Mirant	***Pinnacle West***	Seminole
ALLETE	***CMS Energy***	***Edison Int'l***	***First Energy***	Nebraska Pub. Power	***Portland GE***	***Sempra***
Ameren	***ConEd***	Mission Energy	***Idaho Power***	NYPA	PowerSouth	***Southern.***
AEP	***Constellation***	***El Paso Elec.***	***Integrys***	NextEra	***PPL***	***WGL***
Arkansas Elec.	Covanta	***Energy Futures***	***Jacksonville Auth.***	***NiSource***	***Progress***	***Xcel***
Associated Elec.	***Dominion***					

The next table shows that some key IUSA positions benchmarked with reference to the energy-services group have been compared to relatively few other enterprises.

Position	Data Points	Position	Data Points
CEO	41	Director, Internal Audit	10
COO	17	Director, NY Elec. Distribution	5
VP, Elec. Distribution	7	Director, Elec. Systems Eng.	7
VP, Eng. & Asset Mgmt	19	Director, Elec. System Planning	6
VP, Gas Assets	7	NY President	6
VP, Energy Supply	15	NY VP & Controller	6
VP, Rates & Reg Economics	12	***Average Excluding CEO & COO***	***9***

At least since 2008, the Nominating and Compensation Committee of the ISA board of directors has not used compensation consultants. Neither has the ISA board. ISA management has not used them for at least this period as well, for either ISA or IUSA compensation examinations or analyses. The ISA board has not retained any consultants in recent years for the purposes of examining IUSA compensation.

b. January 2009 Executive Competitive Pay Assessment

Hewitt Associates LLC ("Hewitt") "refreshed" a September 2007 competitive pay assessment for approximately 65 Energy East executives and managers. The assessment examined base pay, target total cash compensation, annualized value of long-term incentives, and target total direct compensation. Hewitt assessed the following Energy East units (revenues identified by Hewitt in parentheses):

- Energy East Management Corporation (EEMC): $5.2 billion
- Utility Shared Services (USS): $5.2 billion
- New York Companies: $3.5 billion
- Connecticut Companies: $0.9 billion
- Central Maine Power: $0.6 billion
- Non-Utilities: $0.5 billion.

The assessment of EEMC (one of two service companies existing at the time) used a blend of energy-service companies and a broad group of general industry companies. Hewitt made size adjustments based on revenue. Hewitt's peer group of 36 energy-service companies came from its *Total Compensation Measurement*™ databases. The Hewitt assessment provided measurements against the peer groups' median and 75th percentile.

IUSA's reported operating revenues were $5.07 billion for calendar 2008; *i.e.*, close to the level used by the consultant. They dropped significantly, however, in following years: (a) to be $3.67 billion for 2009, and (b) to $3.61 billion for 2010. The 28 peer group companies whose distribution utility operations comprise a large share of their business would, as a group, have much higher revenues by 2010. The average revenues of the 28 were close to twice the size of IUSA's corresponding amount, and the group's median ($5.4 billion) was also much higher. The general industry group consisted of 448 companies with median revenues of $5.3 billion.

Hewitt found that EEMC compensation generally fell below median levels, making the following specific points:

- Base and target bonuses at low end of norms
  - Base: 10 percent below
  - Target Total Cash: 16 percent below
- Long-term incentives significantly market trailing
  - Long-Term Incentives: 14 percent below
  - Target Total Direct: 16 percent below
- Eligibility for long-term incentives more restricted than market.

Hewitt made similar findings about USS (the other service company existing at the time). The New York companies were reasonably competitive for base pay, but trailed the market in both cash and long-term incentives, producing total direct compensation 27 percent below the market median. Similar results applied for CMP, but the Connecticut and non-utility companies were substantially lagging the market medians in base and incentive compensation.

c. July 2010 Pay and Incentive Competitive Assessment

Hewitt performed this assessment, which examined approximately 60 executives and directors. This time, the energy-service peer group members (shown below) averaged $6.5 billion in revenues. Those members were:

AEI Services	Constellation	Kinder Morgan	Progress Energy
AGL Resources	DRI	Mirant	Questar
Allegheny Energy	DTE	NYPA	Reliant
Ameren	Dynegy	NiSource	SCANA
AEP	E.ON	PacificCorp	Sempra
Black Hills	Edison Intl.	PG&E	Southern Co.
CenterPoint	Energy Future Holdings	Pinnacle West	SUEZ North America
Cleco	Entergy	Portland GE	TVA
CMS Energy	KCP&L	PPL	WGL Holdings

The results again showed that compensation trailed market medians, as the next chart demonstrates. Eligibility for long-term incentives remained less extensive than the market. IUSA also placed more emphasis on base pay (65 versus 56 percent) and less on long-term incentives (14 versus 24 percent) than did the comparison group.

Group	Base	Target Incentive	Target Cash	LTI	Target Total	Group	Base	Target Incentive	Target Cash	LTI	Target Total
IUMC[1]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	NYSEG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CMP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	RG&E	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	SCG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aggregate Affiliate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	***Aggregate IUSA***	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] The service company replacing EEMC and USS.

d. April 2010 Competitive Market Assessment

The previous consultant examinations considered the compensation of directors and executives. Towers Watson refreshed a 2007 examination of base and total cash compensation for IUSA positions below the director level. The consultant examined 14 salary surveys, and found benchmark data for 155 positions of the 163 selected for analysis. The 155 positions covered 49 percent of the 2,051 total IUSA employees below the director level. The numbers for NYSEG, RG&E, and IUSAMC were representative of this level of coverage. The study found the following comparisons to the market medians developed.

Unit	Base	Grade Midpoint	Total Cash	Unit	Base	Grade Midpoint	Total Cash
CMP	[redacted]	[redacted]	[redacted]	RG&E	[redacted]	[redacted]	[redacted]
CNG	[redacted]	[redacted]	[redacted]	SCG	[redacted]	[redacted]	[redacted]
NYSEG	[redacted]	[redacted]	[redacted]	IUSMC	[redacted]	[redacted]	[redacted]
Overall	[redacted]	[redacted]	[redacted]				

7. Individual Performance Management

IUSA's individual performance management program operates under a fairly typical structure. It focuses on two key measures: (a) results (*i.e.*, outcomes that individuals achieve), and (b) competencies (*i.e.*, how they achieve those results). The process operates under three linked, annual steps, which employees and supervisors conduct together:

- Performance planning (November-December)
  - Developing objectives (focusing on making them specific, measurable, within an employee's accountabilities, challenging but attainable, and time bounded)
  - Reviewing employee competencies (focusing on the ability to execute, people skills, business and technical knowledge, and facilitation of change) pursuant to a list of clearly stated characteristics for leaders/managers and for individual contributors
  - Creating a development plan (focusing on way to improve competencies for present and future assignments)
  - Reviewing and approving performance plans (business area leaders approve the plans created by employees and supervisors)
- Performance assessment
  - Mid-year review (June-July): Employees and supervisors discuss plan status and refocus for remainder of year if necessary; this review produces a Mid-Year Performance Review Checklist.
  - Year-end review (October-February): Using input from the supervisor, the employee, and the employee's colleagues, performance is rated (high, good, and low).
    - Employee and colleague self assessments

        - Supervisor ratings of performance and competencies (75 percent weighting to performance results; 25% to competencies)
        - Supervisor determination of whether development plan has been met
        - Optional (to supervisor) sessions to compare employee performance with that of peers
        - Calibration: An area-management facilitated process intended to assure consistency, fairness, and employee credibility in the process
        - Calibration Review: Approval and adjustment by the state president and by Human Resources of the final ratings
        - Creation of a 90-day Performance Improvement Plan for employees rated in the lowest category (Low Performer), with termination upon failure to progress satisfactorily under that improvement plan or upon the receipt of a second low performer rating within three years.
- Reward decisions (January-March)
    - Merit increases, variable pay, promotions, and special assignments are linked to performance assessment results.

IUSA intends that individual employee objectives cascade downward from IUSA objectives. Senior IUSA executive management (including the state presidents) determines IUSA objectives in October of each year. These objectives form the basis for the development of business area and department objectives, which then guide the development of objectives specific to individual employees. Each of the employee-specific objectives receives a numerical weighting.

K. Compensation – Conclusions

17. Neither the ISA nor the IUSA boards engages substantially in the establishment and management of compensation for U.S. senior management and executives. *(Recommendation #8)*

Neither the parent board nor any of its committees substantially engages in compensation matters involving U.S. executives. That role is nominally exercised by an IUSA board that is dominated by senior ISA executives based in Spain; however, even this board takes only a limited compensation role. To the extent that ISA Group-level compensation policies and targets affect U.S. compensation, they have not been exercised in a timely or consistent manner. The IUSA board has nominal responsibility, but has not demonstrated strong attention to compensation.

The IUSA board has no compensation committee. The board appears to have taken no role in establishing senior management and executive compensation packages. A review of IUSA board shows comparatively little attention to the types of issues that U.S. utility holding company boards typically address with respect to compensation, such as benchmarking and continuing attention through the year to progress against incentives. There have been few or no detailed materials about such matters presented to the IUSA board. The IUSA board minutes show no indication of approval of incentive targets or awards for 2010. The minutes briefly mention the incentive awards for 2010 and the establishment of incentive targets for 2011, again without the appearance of substantial documentation or of discussion or questioning by the board.

Neither the ISA nor the IUSA board made use of compensation consultants. IUSA executive management has used them routinely, but the lack of board direction of compensation consultant work, combined with the lack of IUSA board independence, leaves too much control of compensation program design and rewards under management control. The consultants, apart from the lack of control over their use by the board, show a sound approach in critical respects, such as:

- Benchmarking reviews have occurred at regular intervals.
- Reviews of senior and more junior groups have been performed by separate consultants.
- Consultants used are leaders in the field.
- Studies have examined a suitable range of positions.
- Studies have examined not only total compensation, but each principal component (base salary, short-term incentives, long-term incentives).
- Consultants have noted trends and developments in industry compensation practices.
- Both energy industry and broader commercial peer groups have been used (although a subsequent conclusion addresses concerns about peer group comparability in more recent consultant work).

18. There exist clear definitions and documentation of the program of executive compensation, but their implementation recently has lacked clarity and certainty in some respects. *(Recommendation #9)*

Both ISA and IUSA clearly define and document the approach and elements that comprise the compensation programs for senior management and executives. Available documentation and communication to covered employees make clear, with a significant recent exception, the three elements of the compensation program and the range of participants and targets affected. The incentive elements of the program operate on a sufficiently objective basis. IUSA also applies suitable controls, supported by Internal Audit and Human Resources personnel, in assuring that performance metrics and other key determinants get applied correctly and without bias.

The ISA Global restructuring that created the Networks organization produced a notable level of uncertainty about compensation during 2011. Top ISA management anticipated that this restructuring would generate two new sets of performance targets (measured across all affected ISA entities, including IUSA as a part) that would form part of the drivers of incentive compensation. The first set, for the Networks organization, were not finalized by mid-year. The second set (Corporate Function targets), applicable generally to what one would describe as support groups, never became established at all. Effective use of incentive targets require that affected employees know them for the entire duration (or at the very least the vast majority) of the performance period for which they will drive work priorities and compensation incentives. For them to be uncertain (as to amount, and even existence at all) for half the measurement period or more is counterproductive. Equally troubling was the apparent lack of common understanding between ISA and IUSA executives about their applicability to IUSA in the first place. There should be complete commonality of communication and understanding between ISA and IUSA about U.S. compensation practices, to the extent that either ISA senior executives or the board review and approve U.S. compensation practices.

19. IUSA has designed its compensation programs to be sufficient to attract and retain personnel with the necessary levels of skill and experience, while aligning rewards with the achievement of established goals and objectives; however, it appears that IUSA has

become increasingly smaller in comparison to its peer group in recent years. *(Recommendation #10)*

The range of IUSA positions and the advancement ranges within them conform to what we have seen at other similar utility-industry enterprises. The division of compensation into the three main elements (base salary and short- and long-term-incentives) is generally in line with industry experience. The processes for assessing employee performance is reasonably objective and it links appropriately to compensation decisions made routinely (annually for incentives and every 18 months for base compensation). There is sufficient involvement of Human Resources expertise to support objective and appropriately calibrated salary changes and incentive compensation awards.

Benchmarking with peer groups does not on the surface disclose too rich a compensation program, but we note that IUSA is falling in size relative to the energy-services group used for recent benchmarking. That peer group also contains many companies that engage in businesses that fundamentally differ from that of IUSA, which is predominantly an electricity and natural gas distribution utility. Many of the energy-service "peers" are engaged primarily in electricity generation, retail energy supply, and alternate energy or propane production. Many others are public power or cooperative electricity providers and they provide generation and transmission, but not distribution utility services. Of those who do engage in large electricity or natural gas distribution services, IUSA has fallen from near the middle of the group to well below average and median in the past two years. Part of the reason is the IUSA sale of New England gas distribution utilities, but changes in peer group membership have also served to increase the group's median and average revenues significantly, while IUSA's has fallen.

We also observed that a significant number of senior positions can be measured against only a few members of even this peer group. Small sample sizes limit the persuasiveness of any comparisons drawn.

Consequently, we believe that IUSA is not at present in a position to take comfort in the fact that, versus the benchmarks used, its senior management team falls beneath the 50th percentile.

20. IUSA maintains at the general level a strong linkage between performance by and compensation of managers and executives, but the metrics used: (a) inappropriately link U.S. compensation to ISA Global performance, (b) have not "stretched" to promote performance improvement, and (c) do not sufficiently emphasize "input" as opposed to "outputs." *(Recommendation #11)*

The most effective use of objectives as compensation incentives lies in a strong linkage with corporate, business area, work group, and personal goals. Objectives applicable to each employee, beginning with the CEO, should cascade down from the general to the more specific, as one reaches successively lower levels in the population to which annual incentives apply. Conversely, as one moves from the lowest to the highest levels in that population, the amount of incentives available (or "at risk") should increase steadily and significantly. IUSA incorporates these elements carefully into its compensation program. Our review found a particularly strong correlation between goals at all levels and the metrics used to determine annual incentive payments. Of particular note was the careful alignment of NYPSC-imposed metrics with incentive targets. IUSA has clearly sought to enforce the need for meeting the performance levels embodied in those metrics.

Linkage to ISA Global Performance

Overall performance at the ISA Global level and Networks Group performance comprise two of the categories assigned weight in IUSA's annual incentive plans. IUSA forms a very small part of ISA Global and of ISA Networks business. IUSA has very little ability to influence global results. ISA's other U.S. businesses comprise II&C (the engineering and construction affiliate) and Renovables (the wind generation affiliate). IUSA actually has some material interests at variance with those of II&C. Even in the case of Renovables, it seems clear under the circumstances that any substantial attention paid by IUSA personnel to the wind company's interests would constitute a diversion. Considering the size of IUSA, the off-continent locations of the other principal ISA Networks businesses, and the need for an arm's-length (if not more distant) relationship from II&C, it is not appropriate that ISA tie substantial amounts of incentive compensation to ISA Global or Networks performance. Also making performance at this level a "trigger" for incentive payments to IUSA personnel is particularly troublesome.

Lack of Stretch in Performance Targets

A review of performance against goals shows a routine ability to meet them (most very comfortably), but no significant increase in the goals to promote continuing improvement. It is not evident that IUSA regularly examines performance against objectives for the purpose of determining whether it can induce improved performance through stretching goals. Seeking continuous improvement cost effectively through stretch goals is an accepted element of effective management.

Input versus Output Targets

IUSA, as do most other utility enterprises, uses targets that measure the consequences, rather than the causes of good performance. Examples include reliability measures (*e.g.*, CAIDI), and performance against capital and O&M budgets. These measures are lagging, rather than leading indicators. For example, CAIDI is not directly managed, but results from the performance of specific activities (*e.g.*, inspections, repairs, rebuilds). These activities comprise the controllable inputs that ultimately drive reliability performance. Effective performance measurement and linkage to compensation should reward adherence to well-designed plans for conducting these activities. The same is true for costs. If actual versus budgeted costs look good only because planned activities are skipped or projects delayed or reduced in scope, rewards are not appropriate. Our review of IUSA's targets shows a lack of robustness in measurement of inputs and leading indicators.

While that lack is not totally out of character with the industry, two observations are important. First, management has acknowledged that its ability to take meaningful, detailed leading "input" measures is still in development. Second, we consider a focus on such leading measures to be a core element of leading thinking in the industry on cost management. So should it be with respect to measurement of performance for rewarding employees.

We found the measures used for incentive compensation to be sufficiently objective and directly relationship to improvements in service and cost. This aspect of IUSA's compensation program constitutes a strength, when comparing it to other utilities whose programs we have examined.

L. Compensation - Recommendations

8. Give the IUSA board the full power to design and determine the compensation of IUSA employees. *(Conclusion #17)*

The IUSA board is, whether one finds its design, composition, and operation optimum or not, the closest governing body to IUSA senior management. It is not now constructed to address executive compensation in a manner familiar in the U.S. industry. Giving it accountability for determining executive compensation should, however, make it preferable to the other available alternatives (U.S. executive team responsibility to set its own compensation, assigning the matter to the parent board, or permitting HR leadership in Spain to do so). Requiring the board to take direct responsibility and supporting it through administrative and structural means (engaging in the details of compensation benchmarking information from outside consultants and creating the compensation committee typical of parent boards are examples). We believe that the issues raised about governance in Chapter II make this a less than fully comforting solution, but at least an improvement, given the compensation concerns raised by the conclusions of this report section.

The only costs we anticipate from implementing this recommendation would be compensation committee fees for the outside and independent directors, should that be part of the solution identified by the IUSA board. Should the board create such a committee, a majority of its members should be outside and independent directors. It is difficult to envision how the other members, who come predominantly from a single, Spanish oriented compensation program could be expected to develop both the expertise and the objectivity to address the elements that make U.S. utility compensation different.

9. Make the IUSA board the sole authority for establishing and measuring IUSA incentive compensation and assure the creation of all goals by the start of the period they address. *(Conclusion #18)*

It would seem self-evident that the goal of incentive compensation is defeated if targets are established after the time when participants are supposed to be working to meet them. We are given to understand that a one-time, major organization change caused uncertainty that led to delay in establishing some goals applicable to IUSA's AIP last year. The temporary disruption of such change is understandable; more difficult to fathom is the thinking behind why the correct reaction to it, from a compensation perspective, was to leave important parameters open until the third quarter, rather than to defer AIP changes until the uncertainties could be resolved. Equally troubling is the lack of consensus between Spain and IUSA on whether the measures still open for consideration in Spain as the year progressed even necessarily affected IUSA personnel's compensation.

We believe that keeping Spain off the critical path for IUSA compensation determination is clearly the best path. It locates authority with IUSA leadership and it reduces the potential for confusing employees about compensation. The IUSA board is already dominated by Spanish executives, including those responsible for compensation at the Global level. There need be no more layering of authority over that board.

There is no cost to implementing this recommendation. The benefits are the production of clarity in how IUSA personnel will be compensated and the assurance that they will know what priorities are at a time when they have the power to affect them.

10. Re-evaluate and reconstitute the peer groups used to benchmark IUSA compensation. *(Conclusion #19)*

A common observation from our reviews of utility compensation benchmarking is the difficulty in concluding that groups used for compensation benchmarking are not in fact larger and subject to greater risk. We have not found groups that are clearly unrepresentative, but it is not easy to find companies that comfortably appear to be "right in the middle" either. As time has passed, the failure to make more significant changes to the IUSA peer group may be making IUSA less representative. IUSA needs to re-examine the group for size, for nature of business, and for the existence of truly comparable senior positions.

Our review of where IUSA compensation stands versus the groups for the positions benchmarked does not disclose concern about current "overcompensation" on a group basis. IUSA positions collectively show a gap that places them below the middle. We do not make this recommendation on the basis of direct concern about compensation that is comparatively too high or higher than IUSA needs to pay to attract and retain a capable executive and management team. That said, IUSA should strive to assure that its peer groups remain truly representative over time.

Creation of a different group may increase the cost of outside services, depending on the availability of consultant information from a sufficiently broad group. We would not recommend an immediate change if the result is to cause a substantial jump in fees for obtaining peer group information.

11. Delink IUSA incentive compensation from ISA Global performance, incorporate more stretch in targets, and incorporate input measures. *(Conclusion #20)*

Senior ISA leadership emphasizes the independence of "local" operations, points out that, apart from general strategies, each subholding company forms its own plans, objectives and targets. ISA has also emphasized and emphasized again to Liberty how small a portion of ISA's overall operations IUSA represents. Nevertheless, ISA hinges incentive compensation for IUSA managers and executives on how well ISA performs at the global level and on how well Networks (*i.e.*, utility) operations perform. It is curious for ISA, on the one hand, to so strongly distinguish its structural and operating model from that of the typical U.S. utility holding company, while, on the other hand, relying upon it to support the concept of tying subsidiary (here, IUSA) compensation to overall performance.

We believe that the need for an IUSA focus on U.S. utility concerns calls for elimination of compensation based on performance that are not only continents away, but also so large as to render U.S. influence on them negligible. Moreover, tying IUSA compensation to affiliates

Renovables and II&C can be contrary to U.S. utility interests. The decision by ISA to embed II&C's subsidiary into IUSA operations (discussed in Chapter II) is a clear example. ISA should eliminate from incentive compensation targets and triggers all performance "up the line" from IUSA. We think a very narrow exception for the IUSA CEO would be appropriate, but would, even there, sharply constrict the amount at risk due to performance not directly controlled by IUSA. Another exception may be appropriate for structured, focused improvement efforts that engage multi-affiliate groups in activities designed to produce mutually beneficial improvements. Again, such exceptions should be narrow and comprise comparatively small portions of amounts at risk for IUSA personnel.

We also consider repetition of targets comfortably met in prior periods to be problematic if the practice is too widespread. Incentive compensation targets should be re-examined carefully each year. Even where such review determines base targets to be appropriate, there should at least be some weighting of awards size toward higher ends of the targets. This is true even for targets established as a result of regulatory involvement, as our understanding of those targets is that they do not represent public views of highest attainable performance. IUSA would benefit from a process more geared to finding ways to improve performance that is "down the middle" in terms of existing metrics where the cost of doing so "worth the candle."

Finally, as IUSA moves toward the establishment of "input" measures (see the recommendations of the preceding section of this chapter and of Chapter XIII), they should be combined with budget performance targets to assure that incentives are not obtainable without achieving the units of work or productivity underlying the formation of budgets.

Inherently, well-designed incentive compensation targets are net beneficial. If performance targets are not met, then there are no costs. If they are, then the increased costs have already been determined worth the cost savings, service improvements, or other "goal lines" targeted.

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Chapter II: Corporate Structure and Governance

Conclusions

1. **IUSA operates within a corporate-entity structure whose design can promote and support the identification of New York utility needs on a timely and sufficient basis.**

2. **The way that ISA has executed its organizational approach to U.S. utility operations has led to challenges for U.S. management.** *(Recommendation #1)*

3. **The introduction to the U.S. of a close organizational alignment between IUSA and II&C poses great risk for IUSA, without clear, compensating advantages.** *(Recommendation #1)*

4. **IUSA has during 2011 been actively and appropriately considering the costs and benefits of legal consolidation of the New York utilities.**

5. **IUSA is aware of the differences in rate categories and levels, and has been appropriately engaged in efforts to address them.**

6. **The IUSA organization and executive structure appropriately focuses on New York utility needs and promotes efficiency through a notable level of consolidation of functions performed in common for U.S. utilities.**

7. **IUSA's dispersal of functions key to the operation of its gas business is unsound, given the circumstances here.** *(Recommendation #2)*

8. **The IUSA executive team does not convincingly exhibit the hallmarks of a fully empowered and fully synchronized group.** *(Recommendation #3)*

9. **IUSA executives are fully engaged on and aware of New York conditions, needs, priorities, resources, customer needs, and public requirements and expectations.**

10. **The IUSA board has not undertaken structured and regular self-assessments of top IUSA management.** *(Recommendation #4)*

11. **ISA operates under a structured and comparatively well documented set of governance policies and guidance, procedures, and controls.**

12. **The parent board consists of distinguished and very capable individuals.**

13. **The structure and scope of parent board organization and activities differ significantly from what is generally accepted in the case of U.S.-based utility companies.** *(Recommendation #5)*

14. **ISA does not strongly emphasize board member diversity of business and operating skills and experience, which contrasts the Company with what we have observed at major U.S. utility enterprises.** *(Recommendation #5)*

15. **The parent board does not provide a substantial level of independent oversight over New York utility operations.** *(Recommendation #5)*

16. **The IUSA and the IUSA subsidiary boards provide a more detailed level of oversight, but they are dominated by Spanish executives, which continues to leave an "independence" gap by comparison with U.S. utility holding companies.** *(Recommendation #5)*

17. **Senior Spanish executives and the parent board do not take a direct interest in or have more than very general knowledge of the details of U.S. regulatory requirements.** *(Recommendation #6)*

18. **Routine information sources available to European directors (and any senior managers with significant actual or potential influence over New York operations) should be at a scope, level of detail, and frequency to provide them with sufficient information to carry out their responsibilities as they affect those New York operations.** *(Recommendation #5)*

19. **Outside consultants have reviewed board performance relative to peers, but there had been no self-assessments at the time of our audit work.** *(Recommendation #7)*

20. **Management takes what, from our experience with many other utilities, is an unusual perspective on regulatory transparency.** *(Recommendation #6)*

21. **The IUSA board committee responsible for audit matters operates under a typical and appropriate charter and list of functions, is active in defining and exercising committee activities, and has financial expertise, but is concentrated in the ISA executive management members.**

22. **The IUSA audit committee has appropriate powers to execute its duties effectively.**

Recommendations

1. **Suspend indefinitely the provision of services by affiliate IEP to the New York Utilities.** *(Conclusions #2 and 3)*

2. **Consolidate the gas business under a single executive reporting to the COO.** *(Conclusion #7, Chapter VII Conclusion #2, Chapter IX Conclusion #4, #15, #17)*

3. **Streamline executive communications links and focus IUSA leadership under a more fully empowered CEO, emphasizing U.S. operation's needs.** *(Conclusion #8)*

4. **Institute formal IUSA board evaluations of CEO performance and review of CEO evaluations of other top management incumbents.** *(Conclusion #10)*

5. **The gaps between ISA governance and what one would expect for a company with the breadth of operations of IUSA do not lend themselves to concrete, executable change recommendations.** *(Conclusions # 13 through #16 and #18)*

6. **Make IUSA personnel a more central voice in communicating regulatory requirements, expectations, decisions, guidance and other matters to senior Spanish executives and the parent board and establish vehicles to make those audiences more aware of U.S. regulatory issues.** *(Conclusions #17 and 20)*

7. **Institute yearly self-assessments of board performance.** *(Conclusion #19)*

Chapter III: Affiliate Transactions

Conclusions

1. **NYSEG and RG&E engage in a significant amount of affiliate transactions. Support from the service company and work on behalf of each other comprise most of the dollar amount of these transactions, but the fraction involving other affiliates has been growing.**

2. **IUSA categorizes as "convenience payments" some transactions that are actually associated with services performed by one affiliate on behalf of another.** *(Recommendation #1)*

3. **The Company's annual budgeting and service-agreement processes offers sufficient opportunity for NYSEG and RG&E to address the services provided by the service company and other affiliates.**

4. **The company's processes for monthly review of affiliate transactions offer sufficient opportunity for NYSEG and RG&E to monitor the affiliate-provided service performance.**

5. **The Company's affiliate transaction costing methods meet the requirements of the New York Code of Conduct.**

6. **The NYSEG and RG&E affiliate service agreements are adequate in form and content, but include a number of out-of-date elements.** *(Recommendation #2)*

7. **NYSEG and RG&E executed service agreements with almost all of the affiliates to which they have provided or from which they have received services during 2009, 2010, and 2011; however, a small but significant amount of affiliate transactions during 2009 and 2010 were not covered by service agreements.** *(Recommendation #3)*

8. **The Company's inter-affiliate billing and payment process provides an adequate means for NYSEG and RG&E to review and approve the accuracy of the charges for affiliate transactions.**

9. **A significant percentage of the payments for inter-affiliate transactions between NYSEG and RG&E and their affiliates have not been made or received in a timely fashion.** *(Recommendation #4)*

10. **The Company's cost-assignment methods are adequate to provide accurate and comprehensive cost assignment of common costs to affiliates, and are consistent with the New York Code of Conduct requirements.**

11. **The Company's cost manual and service agreements document at a high level the methods used to allocate and assign inter-affiliate costs to NYSEG and RG&E; however, some of the details of the documentation are no longer applicable or necessary**

and there appears to be limited documentation of the detailed cost allocation procedures. *(Recommendation # 2)*

12. **IUMC has adequate systemic and procedural controls in the accounting and cost assignment process to prevent affiliate cross-subsidization, but they do not appear to be consistently applied.** *(Recommendations #3 and #5)*

13. **The Company has limited training or a comprehensive policy document to provide guidance to employees in the appropriate assignment of affiliate transaction costs.** *(Recommendation #5)*

14. **The Company's stated cost assignment policy is to give first preference to directly assigning costs and next to use a cost-causative method to allocate costs; however, IUMC directly assigns a relatively small proportion of costs to affiliates. Most of the remaining costs are allocated using general rather than cost-causative allocation.** *(Recommendation #5)*

15. **IUMC has an adequate cost-assignment review process.**

16. **IUMC's allocation factor calculations are generally accurate and sufficiently documented.**

17. **IUMC's overhead and clearing account processes are adequate; overhead calculations are appropriate and accurate.**

18. **There exist sufficient means for employees to properly assign their time to codes that allow appropriate direct charging and allocation for affiliate transactions.**

19. **The Company's time reporting system and processes contain controls to assure accurate time reporting and appropriate assignment of labor costs, but these controls have not always sufficed to prevent errors.** *(Recommendation #5)*

20. **The Company requires positive time reporting, which helps to assure proper cost assignment by placing the decisions at the level at which knowledge of the specific work performed is the most accurate.**

21. **The Company provides adequate documentation and training in the use of its time reporting system and processes.**

22. **The Company's employee expense reporting process provides adequate means for employees to properly record and assign their expenses.**

23. **The Company's employee expense reporting process includes sufficient controls to assure accurate and appropriate assignment of employee expenses.**

24. **The Company provides adequate documentation for its employee reporting process.**

25. **The Company has an adequate expatriate assignment policy and process.**

26. **There have been some lapses in the Company's compliance with the expatriate assignment policies and procedures, but these appear to have been corrected.**

27. **The Company's financial system and processes provide adequate capability to trace financial transactions, identify the sources of charges, and document cost assignments and allocations.**

Recommendations

1. **Change the identification of transactions as convenience payments to distinguish pass-through payments from expenses incurred in providing inter-affiliate services.** *(Conclusion #2)*

2. **Review and update the language of the inter-affiliate service agreements to reflect the current practice for affiliate transactions.** *(Conclusions #6 and #11)*

3. **Tighten the controls that should prevent inter-affiliate billing without a service agreement.** *(Conclusions #7 and #12)*

4. **Improve the timeliness of inter-affiliate bill payments.** *(Conclusion #9)*

5. **Improve employee training and develop more complete policy documents to encourage more direct and cost-causative charging of service company costs.** *(Conclusions #12, #13, #14, and #19)*

Chapter IV: Load Forecasting – Electric and Gas

Conclusions

1. **The intermediate forecasts are overly simplistic, and fail to capture the broad range of economic and demographic uncertainties facing the Company.** *(Recommendation #1, #2, #4)*
2. **Reviews and revisions to the intermediate forecasts are informal and based on subjective, vaguely defined criteria.** *(Recommendation #2)*
3. **There is no process to revise or update the electric long-term forecast transmission model for planning purposes other than the annual updates of historical peak loads.** *(Recommendation #2)*
4. **IUSA is short on experience and capabilities in the planning and forecasting areas at the staff level.** *(Recommendation #2, #3)*
5. **The various forecasting and planning groups and functions are weak in integration and communications, both laterally and vertically.** *(Recommendation #1)*
6. **Forecasts do not explicitly reflect public policy directives and guidelines.** *(Recommendations #2, #3 & #4)*
7. **Forecasts are consistently applied internally and externally.**

Recommendations

1. **Assign responsibility to the Rates and Regulatory Economics group for supervision and coordination of electric energy and peak load forecasting.** *(Conclusions #1, #5)*
2. **Enhance the intermediate and long-term energy and load forecasting methods.** *(Conclusions #1,#2, #3, #4, #6)*
3. **Enhance the economic and forecasting capabilities and competencies.** *(Conclusions #1, #4, #6)*
4. **Perform a comprehensive electric load research program.** *(Conclusion #1, #6)*
5. **Assess alternative forecasting methods.** *(Conclusion #1, #6)*
6. **Designate an oversight committee to address the management and organization issues.** *(Conclusions #5)*

Chapter V: Wholesale Market Issues

Conclusions

1. **The transmission network is maintained in such a fashion to meet the reliability needs for the delivery of electric supplies to all customers served by NYSEG and RG&E. Furthermore, the transmission network does support access to a range of competitive suppliers to sustain New York's competitive wholesale market.**

2. **The distribution network is maintained as required to support the installation and operation of distributed energy resources including distributed generation systems and such renewable resources as solar electric storage and wind generation.**

3. **The Companies' strategic plans do not address the dynamics of the wholesale market and specifically identify goals and objectives that will support the needs of their retail customers in the wholesale supply and delivery of electricity.** *(Recommendation #1)*

4. **The Companies' capital and operating budgets do not demonstrate a direct linkage between each major line item and a specific strategic objective identified in the strategic plans.**

5. **The Board of Directors have not enumerated its commitment to wholesale competitive markets as demonstrated by a continuum of communications that support investments in the Companies' generation interconnection, and Smart Grid technologies, as well as other measures that protect the short and long term interests of its core customers.**

6. **The Companies' energy procurement and trading desk is managed by a team of competent procurement specialists who abide by a strict code of conduct and comply with all business and regulatory standards.**

7. **The Companies have demonstrated active participation in those NYISO proceedings that can affect the short and long term interests of its retail customers.**

8. **The Companies were able to demonstrate how their participation supports the development of a more robust and efficient energy infrastructure via the support of Smart Grid technologies, renewable resources and demand side management programs.**

9. **Emerging regulations and transmission planning requirements will significantly increase the demand for participation and support before FERC, the NYISO and NERC at a time when the Companies have experienced diminishing resources.** *(Recommendation #2)*

Recommendations

1. **The Companies should prepare a strategic assessment focused on wholesale market goals and objectives.** *(Conclusion #3)*

2. **The Companies should create a formal matrix management team to oversee and manage the Companies' participation in NYISO, FERC, NERC, NPCC, etc. proceedings and issue assessments.** *(Conclusion #9)*

Chapter VI: System Planning - Electric

Conclusions

1. **The Companies do not have a long-term master plan.** *(Recommendation #1)*
2. **The decision-making process does not consider risk in any measurable way, whether quantifiably or qualitatively.** *(Recommendation #1)*
3. **The distribution planning guidelines are not approved by senior management, and there is no formal process for vetting and sanctioning any changes in design criteria.** *(Recommendation #2)*
4. **The planning processes specifically reflect regional differences, as planning is performed on a divisional basis.**
5. **The transmission planning guidelines do not elaborate on the economic factors, assumptions and criteria for evaluating alternative solutions to identified transmission and sub transmission requirements.** *(Recommendation #3)*
6. **The prioritization process is uniformly applied; however, there is no clear understanding of how and why the parameters chosen establish the best rating system.** *(Recommendation #3)*
7. **There is no structured approach to cost benefit analysis.** *(Recommendation #3)*
8. **The transmission planning group uses the PTI PSS computer software for their evaluation of transmission upgrade requirements; the Company does not necessarily make the best use of the available features provided in this suite of analytical tools.** *(Recommendation #4)*
9. **The adequacy of the quantity of experienced staff is questionable.** *(Recommendation #5)*
10. **The Companies do not participate in any industry wide benchmarking or best practices programs.** *(Recommendation #6)*

Recommendations

1. **Modify transmission planning process to include an assessment of risk and uncertainty.** *(Conclusion #1 and #2)*
2. **Prepare a comprehensive distribution planning procedures manual.** *(Conclusion #3)*
3. **Perform a reevaluation of transmission planning prioritization criteria.** *(Conclusion #5, #6, #7)*
4. **Retain a power systems engineering firm to perform an independent needs assessment of its transmission planning models and methods.** *(Conclusion #8)*
5. **Hire an additional experienced transmission planner.** *(Conclusion #9)*

6. Participate in one or more transmission and distribution benchmarking (best practices) programs. *(Conclusion #10)*

Chapter VII: System Planning - Gas

Conclusions

1. **There is no formal or informal long-term planning process, vision or plan at the companies.** *(Recommendation #1)*

2. **The organizational structure, including the recent reorganization and reassignment, is not conducive to long-term planning.** *(Recommendation #1, Chapter II Recommendation #2)*

3. **The companies have a well-developed plan for dealing with aging infrastructure, e.g., replacement of leak-prone pipe (cast iron and bare steel).**

4. **The companies perform annual planning as a component of the annual budgeting process.**

5. **The Companies' system models are not up-to-date, which limits their accuracy and usefulness.** *(Recommendation #1)*

6. **Iberdrola does not have a plan to upgrade its system monitoring and control capabilities.** *(Recommendation #1)*

7. **Iberdrola has initiated a project team to examine business opportunities associated with Marcellus Shale and other formations.**

8. **The Company has not developed scenario or contingency plans for the impacts of Marcellus Shale (and potentially Utica Shale) on its gas supply despite the enormous potential and favorable positioning of some portions of the service territory.** *(Recommendation #1)*

Recommendations

1. **Develop a gas system vision, master plan and associated implementation strategy, including designation of the responsible individual(s) and organizational unit(s).** *(Conclusions #1, 2, 5, 6, 8, Chapter IX Conclusion #8)*

Chapter VIII: Supply Procurement - Electric

Conclusions

1. **The companies do not have a comprehensive, long-term approach with clear goals and objectives for an electricity-supply "portfolio design."** *(Recommendation #1)*

2. **The companies have specifically excluded new bi-lateral purchased power contracts, physical hedges and market alternatives that have durations of more than two years as potential components of their electric supply portfolio.** *(Recommendation #1)*

3. **RFP solicitations have not been considered for soliciting and acquiring energy, hedging and capacity resources.** *(Recommendations #2 and #3)*

4. **The reluctance to enter into electric supply PPAs and hedges of more than [redacted] years is based on rate recovery fears.** *(Recommendation #1)*

5. **The companies' planning for electric supply procurement is not sufficiently long-term to capture the load requirements and resources past two years.** *(Recommendation #1)*

6. **The examination of alternative capacity resources and markets to meet NYISO UCAP requirements has not been sufficiently aggressive.** *(Recommendation #3)*

7. **Organization and staffing are consistent with that of effectively managed electric supply procurement groups.**

8. **Daily electric scheduling and bidding operations are effectively conducted with appropriate risk management and approval processes.**

9. **Electric procurement operations do not have a comprehensive and clearly documented process and procedures manual.** *(Recommendation #4)*

10. **Executive committee oversight of the New York companies' risk management processes and credit evaluations are inappropriately located in Spain.** *(Recommendation #5)*

11. **Risk management operates pursuant to a well-structured program with established and enforced policies and procedures and independent oversight.**

12. **Internal Auditing has not tested the electric procurement decisions and risk management decision-making processes.** *(Recommendation #6)*

Recommendations

1. **Develop a comprehensive long-term portfolio management plan with quantified goals and objectives to optimize the electric resource portfolio and related hedging plans.** *(Conclusions #1, #2, #4, and #5)*

2. **Conduct market solicitations for electric energy resources through RFP processes and implement any alternatives identified as superior to the existing plan of energy and hedging instrument purchases.** *(Conclusion #3)*

3. **Conduct market solicitations for electric capacity resources through RFP processes and implement any alternatives identified as superior to the existing plan of capacity purchases.** *(Conclusion #3, #6)*

4. **Document processes, procedures, and guidelines for electric supply and scheduling.** *(Conclusion #9)*

5. **An executive risk management committee should be formed at IUSA that oversees the risk functions and the RMOC and has executive responsibility for risk management.** *(Conclusion #10)*

6. **Internal Auditing should schedule audits of electric procurements, documentation for entering into capacity supply contracts, and daily purchases.** *(Conclusion #12)*

Chapter IX: Supply Procurement - Gas

Conclusions

1. **Organization and Staffing of the Gas Supply group is consistent with its mission, goal and objectives and industry practice.**
2. **Key managers are well qualified and experienced. However, the experience levels of other employees vary dramatically.**
3. **The staffing of the Gas Supply group is very lean and undercuts the ability to address matters beyond day-today operations.** *(Recommendations #3 and 4)*
4. **The organizational placement of Gas Supply within an otherwise all-electric unit tends to weaken the Companies' overall gas business.** *(Chapter II, Recommendation #2)*
5. **Procurement policies and procedures are appropriate and consistent with work requirements.**
6. **Gas Supply has developed and implemented a reasonable strategy to balance reliability and cost.**
7. **Gas Supply's RFP process for winter gas appears unbiased, with reasonable analytical rigor.**
8. **Local production has provided some value to date, and appears to offer very substantial value in the future if IUSA positions itself to maximize the potential benefits.** *(Chapter VII, Recommendation # 1)*
9. **The Companies' hedging program is designed to mitigate commodity price volatility, while avoiding the temptation to "beat the market."**
10. **The Companies' portfolios represent an effective diversity of pipelines, storages, and contract expirations.**
11. **The Companies have been divesting upstream pipelines as pooling points become more liquid, which provides benefits by reducing gas costs and increasing flexibility.**
12. **Exploitation of Marcellus Shale and other indigenous sources appears to offer substantial potential for cost savings.**
13. **Data from the capacity releases and off-system sales activities indicates high levels of excess capacity in the past.** *(Recommendation #3)*
14. **Citygate assets appear high based on an outdated and apparently high HDD calculation.** *(Recommendation #3)*
15. **The Gas Control Center is understaffed in terms of both numbers and qualifications of personnel.** (*Recommendation #11, Chapter II Recommendation #2)*
16. **The Gas Control Center physical facilities are significantly deficient. (***Recommendation #2)*
17. **The organizational location of the GCC under an otherwise all-electric organization appears to drive the neglect of the GCC.** *(Recommendation #1 and #2)*

18. **The design day load forecast appears high.** **(***Recommendation #3)*

19. **Short term forecasting is relatively unsophisticated, and exhibits a high level of inaccuracy.** (*Recommendation #4)*

20. **Retail Choice program is a mature program that has approached steady state at NYSEG and RG&E.**

21. **Administration of the retail choice program is generally fair and unbiased.**

22. **Balancing strategies and practices are cost-based and unbiased toward any customer groups.**

23. **Metering and testing programs conform to industry standards.**

24. **The Companies' Lost and Unaccounted for gas percentages are very low.**

Recommendations

1. **Upgrade the Gas Control Center personnel numbers and qualifications.** *(Conclusions #15, #17)*

2. **Upgrade the Gas Control Center physical facilities.** *(Conclusions #16, #17)*

3. **Perform a weather study to determine the proper design day and design winter HDD targets.** *(Conclusion #3, #13, #14, #18)*

4. **Improve the short-term (one-to-five day) forecasting process.** *(Conclusion #3, #19)*

Chapter X: Budgeting

Conclusions

1. **NYSEG and RG&E have been unable to execute their capital expenditure plans on a timely basis, with significant problems in 2010 and 2011.** *(Recommendation #1)*

2. **IUSA does not provide adequate capital project designs, cost estimating and project planning to support the timely execution of the NYSEG and RG&E capital budgets.** *(Recommendation #1)*

3. **NYSEG and RG&E have implemented expedited "CAPEX catch-up additions" to electric capital plans in both 2010 and 2011. The cost effectiveness of such expedited efforts is dubious.** *(Recommendation # 1)*

4. **The IUSA Board of Directors has not closely examined, approved, monitored nor taken necessary corrective action regarding the capital expenditures budgets of the utilities.** *(Recommendation #3)*

5. **NYSEG and RG&E 2010 capital budgets were not approved until September 29, 2010, almost 10 months after the budget year began and after significant capital spending had occurred.** *(Recommendation #3)*

6. **O&M budgets are effectively developed, coordinated and consolidated using consistent targets, formats and reports.**

7. **IUSA has effective management reporting processes and reports in place for both executive and manager levels to track, monitor and manage O&M expenditures. Budget variances are appropriately identified and evaluated.**

8. **IUSA has not fully developed longer-term strategies, plans and forecasts that can be linked with three-year rate plans and the annual budget process.** *(Recommendation #2)*

9. **IUSA identifies and initiates expenditure projects and programs with appropriate and consistent system modeling.**

10. **IUSA does not have a common, company-wide analysis system to evaluate and prioritize projects.** *(Recommendation #1)*

11. **The Company does not have informational feedback loops in place to evaluate the quality of capital project analysis and prioritization efforts.** *(Recommendation #1)*

Recommendations

1. **Complete a major overhaul of capital budgeting processes and activities, in order to produce a more structured, realistic, and supported approach to capital budget development and monitoring.** *(Conclusions #1, #2, #3, #10 and #11)*

2. **Develop five-year and ten-year IUSA strategic plans and strongly link with rate plan forecasts and annual budgets.** *(Conclusion #8, Chapter XIV Recommendation #1)*

3. **Enhance the IUSA Board's role in overseeing capital budget formation and monitoring.** *(Conclusion #4)*

Chapter XI: Program and Project Planning and Management - Electric

Conclusions

1. **Internal engineering resources are very low and the extensive use of contracting has not been justified.** (*Recommendation #1*)
2. **The existing team of project managers has sufficient experience in all elements of project management and has suitable credibility within the necessary work processes.** *(Recommendation #1)*
3. **The SAP Work Management system needs changes to be made fully supportive of project management needs.** *(Recommendation #2)*
4. **The roles and responsibilities of the project manager are not clearly defined and understood throughout the organization.** *(Recommendation #3)*
5. **Expectations for project managers are consistent with the authority and resources given the project manager.**
6. **Project management requirements for project participants are not generally consistent across all projects.** *(Recommendation #3)*
7. **Project management principles are applied to significant O&M efforts requiring cross-functional participation.**
8. **A holistic approach to project management is not applied.** *(See Chapter XIII)*
9. **Major components of work do not have consistently tailored "cost management plan" that describes the baseline cost, who is accountable and how costs will be managed.** *(Recommendation #3)*
10. **Kick-off of projects should not be permitted in the absence of reasonably firm scope definition and a cost estimate whose quality is consistent with the current design status.**
11. **Large projects contain "exit ramps" early in the job to permit management reconsideration if costs begin to escalate.**
12. **A program of scope is in place, and identifies scope deviations early, requires analysis of such deviations and the mandatory specification of alternates to mitigate the effects of the deviation.**
13. **The construction program does not uniformly provide for the collective management of small projects.** *(Recommendation #4)*
14. **The project management program does not clearly address contractors performing project management activities.** *(Recommendation #3)*
15. **The role of quality and its relationship to cost and schedule achievement is adequately defined and understood by project participants.**
16. **There are gaps in the linkage between project management and the budgeting systems.** *(Recommendation #5)*
17. **The relative priority of projects and programs are defined in the planning and budgeting process.**

18. **A process for the handling of contingencies has not been defined.** *(Recommendation #3)*
19. **There are not clearly defined project management principles for contractor project management programs on "turn-key" projects.** *(Recommendation #3)*
20. **A documented process is in place for the selection and award of contracts for the vegetation management program, but the delay in marshaling resources and the lack of a more structured cycle-basis are gaps.** (*Recommendation #1 and #2*)
21. **Contracts utilized for the vegetation management program's physical work include provisions that facilitate the utility's management of the work.**
22. **Performance of various contractors is compared regularly with the results used to minimize program costs on a continuing basis.** (*Recommendation #3*)
23. **An adequate number of trained utility supervisors /contract managers is assigned to the oversight of contractors.**
24. **There is adequate oversight and audit of contractor management and payments.**
25. **A documented process is in place for the selection and award of contracts for the energy efficiency programs.**
26. **Energy efficiency programs have a Project Manager and a documented PM process in place controlling costs, schedules and quality, but there is a gap in internal staffing.** *(Recommendation #9)*
27. **There is adequate oversight and audit of energy efficiency field operations, including contractor management, customer installations, payments and rebates.**
28. **Energy efficiency program goal tracking and reporting are accurate, consistent and auditable.**
29. **RG&E and NYSEG have assigned responsibility for assessing industry and governmental (particularly DOE and NIST) developments in Smart Grid development and for assessing current network capabilities and potential improvement plans in light of those developments.**
30. **The utilities have not worked actively with other state electricity distribution utilities and the Commission to address issues of deployment, standards, equipment, services, and cost recovery.**
31. **RG&E and NYSEG have an analytically sound and structured process for examining the costs and benefits of network improvements.**
32. **RG&E and NYSEG have taken a proactive role in examining the availability of funding support for network enhancements, and should aggressively pursue opportunities that will have demonstrable benefits for customers at effective cost.**

Recommendations

1. **Determine the best balance of the number of internal project personnel for the demands for Project Managers, Project Engineers and Schedulers.** *(Conclusion #1, #2)*
2. **Improve the project management functions of the SAP system.** *(Conclusion #3)*

3. **Issue written project management procedures.** *(Conclusion #4, #6, #9, #14, #18 & #19)*

4. **Separate the design function from the delivery function.** *(Conclusion #13)*

5. **Adopt a systematic process in place for updating SAP monthly cash flows during the budget year.** *(Conclusion #16)*

6. **Put vegetation management contracts in place by January 1 of the contract year.** *(Conclusion #20)*

7. **Move to a five year trim cycle on all circuits.** *(Conclusion #20)*

8. **Achieve the benefits of using herbicides in the distribution vegetation management program.** *(Conclusion #22)*

9. **Add in-house technical expertise rather than use contractors.** *(Conclusion #26)*

Chapter XII: Program and Project Planning and Management - Gas

Conclusions

1. **IUSA does not have a workable project management function in either gas operating company.** *(Recommendation #1)*

2. **The Company cannot demonstrate that the current system of using outside engineering resources is as labor saving or cost effective as originally proposed.** *(Recommendation #2)*

3. **Benefits from the increase in capital funding are jeopardized by the lack of engineering and project management resources at both IUSA and their contractors.** *(Recommendations #1 & #2)*

4. **IUSA has a minimally-staffed gas QA/QC function monitoring and overseeing its capital improvement and maintenance program work.** *(Recommendation #3)*

5. **IUSA has maintained an excellent compliance and safety record to-date.**

Recommendations

1. **Formalize Gas Project Management Organization & Process by staffing a Gas project management group with experienced individuals to manage all of the capital program projects, even the small main and service replacements. Additionally, the Companies should formally document project management procedures in a Project Management manual.** *(Conclusion #1 & #3)*

2. **Review manpower requirements to meet the capital and program requirements within the gas organization and make changes accordingly.** *(Conclusions #2 & #3)*

3. **Staff QA/QC to support an effective and functioning QA/QC program for all Gas projects and programs.** *(Conclusion #4)*

Chapter XIII: Work Management

Conclusions

1. **IUSA's culture comports with more traditional, but not holistic, notions of cost management.** *(Recommendation # 1)*
2. **The existing SAP system has the ability to collect adequate and relevant cost information for current budget-management needs.**
3. **Work force management reports include many charts and tables, but contain little analysis or recommendations for dealing with cost variances.** *(Recommendation #1)*
4. **IUSA's approach to cost management is similar to many other utilities, in that it is financially-oriented and focused predominantly on monitoring and oversight.** *(Recommendation #1)*
5. **The strengths of IUSA work management practices can help to form the foundation of an effective cost management system.** *(Recommendation # 1)*
6. **The size of the current IUSA's cost support staff is small and its primary responsibility is to develop and maintain the annual budgets; cost analytical skills and cost control capabilities are lacking.** *(Recommendation # 1)*
7. **The work management processes for all physical work are pertinent, logical, and comprehensive.**
8. **The current work management system module in SAP is essentially a work dispatching and work planning tool, not a complete system that is dynamic enough to manage real-time progress, productivity, and costs.**
9. **The lack of planned or estimated job-hours in work packages reflects a lack of productivity emphasis and specific expectations.** *(Recommendation #2)*
10. **Technical support during field work is responsive for emergency work and adequate for routine work.**
11. **The material requisition system is effective in securing competitive pricing; the delivery of required components is well planned and expedient; the warehousing system is efficient.**
12. **The Transportation Department that manages IUSA's fleet is an effective and efficient operation; it uses a sound fleet staff analysis model in determining the right resource level to meet demand requirements.**
13. **Mechanics at the garages are effective in maintaining vehicles and equipment; work crews are able to mobilize readily to work locations in a reasonably expeditious manner.**
14. **The current Work Breakdown Structure provides adequate and essential details for the managers and supervisors to complete physical work.**
15. **Cost estimating capability in IUSA is a major weakness; the cost estimating process is not uniformly established and approaches to estimating various types of work need to**

be standardized; there are also no full-time internal professional cost estimators. *(Recommendation #3)*

16. **The integrity of the installation-rate databases is a concern; SAP uses the Compatible Unit (CU) to build estimated cost for every work order, but it has not been adequately maintained.** *(Recommendation #3)*
17. **The same work management processes are used in a project environment in a consistent manner.**
18. **The work management system is consistent with the Company budgeting system.**
19. **Qualifications and experiences required of supervisors are appropriate; supervisors respond actively to construction issues and resource needs in the field; supervisory ratios for both NYSEG and RG&E work are all bordering on the high end of the industry range.**
20. **The training programs are generally adequate for physical workers.**
21. **There is no effective resource plan to replace the aging work force.** *(Recommendation #8)*
22. **There is a lack of long-term resource capability analysis; IUSA recognizes this need and has almost completed a work force planning model to plan for T&D Line work.**
23. **The labor agreements by NYSEG with System Council U-7 of the IBEW and by RG&E with Local 36 of the IBEW provide sufficient flexibility and essential provisions for dynamic work force management. However, the 15 percent limitation on Mobile Workforce per NYSEG Memorandum of Understanding will affect its future expansion.**
24. **There is a reasonable degree of flexibility in structuring crew size and allocating resources.**
25. **The work crews from NYSEG and RG&E seldom cross over to work in each other's service territories, making resource use suboptimal.** *(Recommendation #11)*
26. **Assessments of productivity and cost impacts due to the replenishment of retired workers by apprentices are not being performed.** *(Recommendation # 8)*
27. **The OSHA incident rate of Gas Operations (excluding Gas Engineering) has been consistently high.** *(Recommendation #5)*
28. **Overtime levels in Gas Operations are at a reasonable level but T&D overtime levels at both NYSEG and RG&E are very high and a source of concern.** *(Recommendations #6 and #7)*
29. **The external resource requisition procedures are effective in securing competitive pricing.**
30. **In assigning physical work, IUSA has no articulated strategy or specific policies on balancing in-house and contractor resources.** *(Recommendation #4)*
31. **The contractor work forces are generally efficient; there are many unit costing contractors and fixed price contractors.**

32. **The substantial usage of contractors in Electric Operations underscores the question of the adequacy of internal resources.** *(Recommendation #10)*

33. **Contractor productivity is not monitored; the focus instead lies on work completion.** (*Recommendation #9*)

34. **The Contractor Performance Scorecard is not alone sufficient to ensure contractor quality and compliance.** (See *Recommendation #12 in the Performance Measurement section*)

35. **The process of selecting supervisors is sound; the process to fill the position externally when no employees in-house are determined by management to be qualified is also acceptable.**

36. **Low end work, such as flagging and underground location services, is appropriately outsourced.**

37. **The new continuous improvement programs are progressing well, even though the validation of cost savings is handicapped by IUSA's inability to isolate those savings resulting from productivity improvement.**

38. **Productivity measurement has not been a focus of IUSA management.**

39. **There is little documentation on the implementation and effectiveness of lessons learned.**

40. **The Quality Assurance Program for Gas Operations is barely passable and the staffing level is too low to be considered adequate and effective; for Electric Operations, it cannot be acceptable in the long run to rely on supervisors or contracted contingent based workers as the last line of defense in assuring quality and compliance of contractor's work.** *(Recommendation #12)*

41. **The collection of production data at the work order level adequately addresses production, but IUSA has not maximized use of data to manage productivity.**

42. **Effective productivity measurement has been lacking, but development of new KPI items initiated in early 2010 is a step in the right direction, particularly if extended to all repetitive measurable property units in both the Electric and Gas Operations.**

43. **Analysis of performance metrics, in general, is inadequate, with few early warnings of potential problems or recommendations for corrective actions to mitigate factors that threaten targets.**

44. **There is little effort in benchmarking internally.**

45. **There is no participation in external benchmarking.**

Recommendations

1. **Implement a holistic cost-management program.** *(Conclusions #1, 3, 4, 5, and 6)*

2. **Begin monitoring Actual Job-hour expenditures versus Planned Job-hours for Electric and Gas Operations; provide "Planned Job-hours" for all work packages issued to the field.** *(Conclusion #9)*

3. **Enhance the cost estimating capability by establishing a structured cost estimating program.** *(Conclusions #15 and #16)*

4. **Establish a structured approach, policies and supporting guidelines for the balancing of in-house and contractor resources in physical work assignments.** *(Conclusion #30)*

5. **Conduct a root-cause analysis on the continuous high trend in OSHA injury rate in Gas Operations and implement a corrective action program.** *(Conclusion #27)*

6. **Establish a structured corporate approach, policies and supporting guidelines to provide managers and supervisors with a framework to manage non-exempt employee overtime.** *(Conclusion #28)*

7. **Prepare an analysis of overtime expenditures on Electric Operations and Stores, including root causes of the high trends and strategies for attaining a predetermined target.** *(Conclusion #28)*

8. **Develop the capability to continuously assess and monitor the productivity and cost impact of the expected retirement of linemen.** *(Conclusions #21 and #26)*

9. **Include in future contracts a requirement that contractors performing physical work report expended job-hours and quantities installed or completed (at a property unit level).** *(Conclusion #33)*

10. **Evaluate the most cost-effective size of the overall internal work force, including the Mobile Work Force, taking into account such factors as future planned workload, worker versus contractor efficiency and productivity, and work rules; strive to achieve a balanced and cost-effective workforce level.** *(Conclusion #32)*

11. **Promote the ability of NYSEG and RG&E workforces to perform cost-effective work in each other's territories.** *(Conclusion #25)*

12. **Establish a Quality Assurance Organization to maintain the integrity of all the electric work performed.** *(Conclusion # 40 this section; also Conclusion #34 of Resource Management section)*

Chapter XIV: Plans, Controls, Performance Management, and Compensation

Conclusions

1. **IUSA operates under a clear and appropriate set of mission and vision statements and clearly stated corporate objectives, which IUSA makes clear and emphasizes throughout the organization.**

2. **IUSA's goals and objectives balance the needs of stakeholders, including customers, shareholders, employees and regulators.**

3. **IUSA has recently adopted its first five-year plan, and recognizes, but has not yet advanced far in taking a much longer range view of its utility infrastructure.** *(Recommendation #1)*

4. **IUSA has continued to address SOX compliance under the structure and with the methods used prior to ISA's acquisition**

5. **Reductions in key controls have occurred without an examination of their significance from a regulatory point of view.** *(Recommendation #2)*

6. **Annual internal audit plans result from a structured risk assessment process that fully considers New York utility risks, and produces sufficient examination of utility costs.**

7. **Operations audits have not been a focus of IUSA, but comprehensive processes focused on business transformation and best practice institution have produced a strong focus on operations structures, resources, procedures, and processes.**

8. **Prior to two recent affiliates audits conducted after circumstances at National Grid focused attention to the issue, Internal Audit had not been conducting regular examinations of affiliate transactions.** *(Recommendation #3)*

9. **There exist overall an appropriate set of policies, procedures, requirements, reporting, and enforcement of standards of ethical behavior and conflict-of-interest.**

10. **The IUSA Code of Conduct treats affiliate relationships and transactions at too general a level.** *(Recommendation #4)*

11. **The lack of separation between legal ethics functions does not comport with our view of best practice.** *(Recommendation #5)*

12. **IUSA regularly establishes, monitors performance against, reviews, and uses comprehensive and sufficiently quantified performance goals and targets at a high level.**

13. **IUSA employs a comprehensive set of metrics and key performance indicators tied to goals and targets addressing cost and service quality.**

14. **IUSA measurements adequately measure cost and service quality at the "output" level, but have yet to produce comprehensive measures of "inputs."** *(Recommendation #6)*

15. **External and internal benchmarking of performance has not strongly informed IUSA performance management.** *(Recommendation #7)*

16. **The IUSA board examines budget performance and performance against some high-level measures and approves compensation measures, but does so at a level that we consider comparatively very general.** *(See generally the Governance Recommendations of Chapter II).*

17. **Neither the ISA nor the IUSA boards engages substantially in the establishment and management of compensation for U.S. senior management and executives.** *(Recommendation #8)*

18. **There exist clear definitions and documentation of the program of executive compensation, but their implementation recently has lacked clarity and certainty in some respects.** *(Recommendation #9)*

19. **IUSA has designed its compensation programs to be sufficient to attract and retain personnel with the necessary levels of skill and experience, while aligning rewards with the achievement of established goals and objectives; however, it appears that IUSA has become increasingly smaller in comparison to its peer group in recent years.** *(Recommendation #10)*

20. **IUSA maintains at the general level a strong linkage between performance by and compensation of managers and executives, but the metrics used: (a) inappropriately link U.S. compensation to ISA Global performance, (b) have not "stretched" to promote performance improvement, and (c) do not sufficiently emphasize "input" as opposed to "outputs."** *(Recommendation #11)*

Recommendations

1. **Study and apply the ConEd experience in long-term infrastructure planning in forming a concrete plan for long-range infrastructure planning.** *(Conclusion #3, Chapter X Conclusion #2)*

2. **Subject prior and future changes in SOX compliance structure, structure, responsibilities, procedures, practices, and components (*e.g.*, key controls) to a focused analysis of potential impacts on utility regulatory processes and proceedings.** *(Conclusion #5)*

3. **Make examination of affiliate relationships and transactions a recurring element of Internal Audit's plans and provide for clear, timely documentation and reporting of progress in implementing recommendations.** *(Conclusion #8)*

4. **Incorporate into the IUSA Code of Conduct specific statements of IUSA values and principles regarding affiliate relationships and transactions, and summarize and make references to applicable policies, procedures, and guidance.** *(Conclusion #10)*

5. **Make the reporting of the IUSA chief ethics and compliance lead organizationally separate from the general counsel's organization, establish a direct reporting organizational relationship to the IUSA CEO, and provide for regular and confidential reporting to the IUSA board's audit committee.** *(Conclusion #11)*

6. **Develop a series input-based metrics that will permit more robust assessment of cost performance by measuring it against work units accomplished and the productivity achieved in accomplishing those units.** *(Conclusion #14)*

7. **Establish a formal program applying a robust mix of external and internal benchmarks.** *(Conclusion #15)*

8. **Give the IUSA board the full power to design and determine the compensation of IUSA employees.** *(Conclusion #17)*

9. **Make the IUSA board the sole authority for establishing and measuring IUSA incentive compensation and assure the creation of all goals by the start of the period they address.** *(Conclusion #18)*

10. **Re-evaluate and reconstitute the peer groups used to benchmark IUSA compensation.** *(Conclusion #19)*

11. **Delink IUSA incentive compensation from ISA Global performance, incorporate more stretch in targets, and incorporate input measures.** *(Conclusion #20)*