STATE OF NEW YORK DEPARTMENT OF PUBLIC SERVICE
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AUDREY ZIBELMAN
Chair

PETER McGOWAN
General Counsel

September 27, 2013

Lawrence J. Waldman, Chair
Long Island Power Authority
333 Earle Ovington Boulevard, Suite 403
Uniondale, New York 11553

Re: Notice of Completion in Matter No. 12-00314 - In the Matter of a Comprehensive and Regular Management and Operations Audit of Long Island Power Authority Pursuant to the LIPA Oversight and Accountability Act.

Dear Mr. Waldman:

Under the direction of the New York State Department of Public Service (DPS or Department), NorthStar Consulting Group, Inc. (NorthStar) has completed the management and operations audit of the Long Island Power Authority (LIPA or Authority). The final Audit Report is being formally provided herewith to the Board of Trustees and will simultaneously be posted on the Department's Document and Matter Management System (DMM), accessible through its website.

The audit was performed in accordance with the Long Island Power Authority Oversight and Accountability Act (LIPA Act) that was signed into Law on February 1, 2012. The LIPA Act required the Department to conduct periodic audits of LIPA, and specified that the audit should review the following topic areas: (i) the Authority's construction and capital program planning in relation to the needs of its customers for reliable service; (ii) the overall efficiency of the Authority's operations; (iii) the manner in which the Authority is meeting its debt service obligations; (iv) the Authority's Fuel and Purchased Power Cost Adjustment clause and recovery of costs associated with such clause; (v) the Authority's annual budgeting procedures and process; and (vi) the Authority's compliance with debt covenants. The LIPA Act provided further that the audit was to be undertaken in a manner and to an extent that is practicable in the context of the authority's transition to a new management service structure.

In accordance with the LIPA Act, LIPA is required to post the final Audit Report, including findings and recommendations, on its website. The comments received from LIPA and National Grid that accompany the Audit Report should be posted as well. LIPA's comments indicate that it expects the Audit recommendations be accepted in full by the LIPA Board of

Trustees, with implementation of all recommendations prior to the next management and operations audit in 2016. LIPA also has indicated that it plans to work with PSEG-Long Island LLC, LIPA's new service provider as of January 1, 2014, to facilitate implementation of the recommendations in the Final Audit Report, consistent with the terms and conditions of the contract for service.

Sincerely yours,

Audrey Zibelman
Chair

cc: Lynda Nicolino, Secretary to the LIPA Board of Trustees
Via hardcopy and email

Enc.

COMPREHENSIVE MANAGEMENT AND OPERATIONS AUDIT OF LONG ISLAND POWER AUTHORITY

MATTER NO. 12-00314

FINAL REPORT

SUBMITTED TO THE:

NEW YORK PUBLIC SERVICE COMMISSION
DEPARTMENT OF PUBLIC SERVICE

THREE EMPIRE STATE PLAZA
ALBANY, NY 12223-1350

SEPTEMBER 13, 2013

NORTHSTAR CONSULTING GROUP
MANAGEMENT CONSULTANTS

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1. EXECUTIVE SUMMARY

NorthStar Consulting Group, Inc. (NorthStar) was retained by the New York State (NYS) Department of Public Service (DPS or Department) to conduct a management and operations audit of the Long Island Power Authority (LIPA or Authority) pursuant to Matter No. 12-00314. This chapter of our report provides an executive summary of our findings and recommendations. The scope of the audit and the complexity and unique nature of LIPA's organization and operations make it difficult to adequately summarize the audit findings. Accordingly, this chapter focuses on a discussion of several broad findings that cross over many functional areas and are of critical importance for LIPA and its customers as the Authority continues to transition from one primary outside service provider – National Grid plc (National Grid) – to another – Public Service Enterprise Group (PSEG) and its subsidiary, PSEG Long Island, LLC (PSEG-LI).[1]

1.1 Background on LIPA

LIPA is a New York Public Authority with responsibility for providing electric service to approximately 1.1 million customers in Nassau and Suffolk Counties and the Rockaway Peninsula in Queens on Long Island. LIPA acquired responsibility for electric services on Long Island in 1998. LIPA acquired the electric distribution assets and KeySpan Corporation acquired Long Island Lighting Company's (LILCO) natural gas distributions assets, along with LILCO's electric generating assets on Long Island.

At the time that LIPA acquired the electric system, the decision was made to outsource the actual operation of the system to KeySpan. In August 2007, KeySpan was acquired by National Grid plc (National Grid), a company organized under the laws of England and Wales.[2] Effective May 1, 2008, the subsidiaries of KeySpan Corporation began doing business under the name "National Grid." Three major contracts were put in place between KeySpan (now National Grid) and LIPA:

- **Management Services Agreement (MSA)**: The MSA provides for the day-to-day operation of LIPA's Transmission and Distribution (T&D) business, including customer service and support functions. National Grid is paid a management fee that covers all operating and maintenance (O&M) costs, personnel, supplies, and profit. Costs associated with capital projects are reimbursed at cost. The MSA has been modified and amended several times since it was implemented. The MSA will terminate at the end of 2013.

- **Power Supply Agreement (PSA)**: The PSA gives LIPA the rights to the capacity and energy associated with the former LILCO generating plants (PSA units), and specifies the price for that power. The original PSA expired on May 27, 2013. The "Amended and

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[1] Another PSEG subsidiary is the regulated utility in New Jersey – Public Service Electric & Gas (PSE&G)

[2] On February 26, 2006, National Grid and KeySpan entered into a Merger Agreement.

Restated" PSA (A&R PSA) began on May 28, 2013, and ends April 30, 2028, providing LIPA greater flexibility in the use of the PSA units, along with other potential future benefits.

- **Energy Management Agreement (EMA)**: Under the EMA, National Grid was responsible for procuring the fuel for the PSA units, and for all aspects of the bidding and nomination of LIPA's generation with the New York Independent System Operator (NYISO). As LIPA contracted for additional generating capacity, a separate agreement to purchase fuel for the new units (the Purchase Power Agreement units) was implemented. The power management portion of the EMA terminated by its own terms, and LIPA entered into an agreement with Consolidated Edison Energy Incorporated (CEE) for those services.[3] The Fuel Management portion of the EMA continued in effect, expiring on its own terms on May 28, 2013. Following a competitive bid process LIPA entered into a separate contract with CEE for Fuel Management services effective May 28, 2013.

National Grid provides the contractual services primarily with a work force of approximately 1,900 individuals located on Long Island. Many of these personnel were employed by LILCO when it operated the system. Most National Grid Long Island personnel are dedicated to LIPA's electric operations. Notable exceptions include meter reading, billing and the call center which serve both LIPA and National Grid's natural gas customers on the Island. Many services, such as accounting and procurement type functions, are provided by National Grid's Shared Services group or elsewhere within the National Grid USA corporate organization. These personnel are "shared" among other National Grid USA operations.

LIPA is unlike any typical utility. Its unique organizational structure is a product of State Law and it has had to operate its utility business, providing electric power to Long Island ratepayers, within the confines and constraints of its enabling statute. Core functions that are normally central to a utility, such as operations, maintenance and construction work, are executed by National Grid and LIPA has minimal direct involvement in the day to day activities.

Currently, LIPA has direct responsibility for energy supply planning, legal matters, and financial activities (reporting, treasury, credit, debt issuance and management), and for the oversight of activities of National Grid and other contractors. LIPA is led by an Executive Team made up of the top seven LIPA management positions: Chief Executive Officer (CEO) (currently vacant), Chief Operating Officer (COO), Chief Financial Officer (CFO), General Counsel, and the Vice Presidents (VP) of T&D Operations, Environmental Affairs and Power Markets. The Authority currently has a staff of approximately 95.

In anticipation of the expiration of the MSA at the end of 2013, LIPA and its Board of Trustees (BOT) initiated a review of its business processes and options for LIPA's future. Following several studies, the BOT decided on a "ServCo" model, wherein all the operating processes would be transferred to a standalone entity (the ServCo), managed by an outside service provider. The ServCo would contain all the functions and resources necessary to operate

[3] DR 4

the LIPA electric system, specifically eliminating "shared" services by the outside service provider. Practically, this meant that in addition to all of the daily system operating and maintenance responsibilities and the analytical support currently provided by National Grid's Long Island organization, ServCo would contain procurement, all accounting, bill processing, meter reading and customer service functions, which were previously provided by National Grid on some type of shared basis.

Following a Request for Quotation (RFQ)/Request for Proposal (RFP) process, LIPA entered into an Operating Service Agreement (OSA) on December 28, 2011 with PSEG, the largest electric utility in New Jersey. PSEG's subsidiary, PSEG-LI, will provide the day-to-day management and supervision of the operations of the LIPA T&D system and related services and functions, as defined in the ServCo business model, starting January 1, 2014.

LIPA faces challenges in the areas of rates and customer service. When LIPA acquired LILCO's electric distribution assets, the Authority also was given the responsibility for approximately $6 billion in debt related to LILCO's investments in electric generation, transmission and distribution assets, and the decommissioned and non-operable Shoreham nuclear plant. In the years since, LIPA has serviced the old debt and issued new debt associated with T&D investments and maintenance projects, and the procurement and contracting for new generating capacity to meet the needs of its customers throughout the service territory. The continued high level of debt, coupled with property taxes and other fees, means that LIPA's retail rates are second highest in New York State (after Consolidated Edison Companies of New York, Inc. (Con Edison)). LIPA also suffers from poor customer satisfaction, most recently falling to the bottom of the JD Power annual survey. Poor customer perception is the result of many factors, forces and issues which have occurred over time, some arguably even pre-dating LIPA. The response of LIPA to Hurricane Sandy and the Nor'easter in late 2012 compounded prior issues in the public's assessment of the Authority.

This management and operations audit was authorized by the Long Island Power Authority Oversight And Accountability Act (the LIPA Act), which was signed into law on February 1, 2012. The LIPA Act requires LIPA to undergo periodic audits of internal policies and procedures to improve transparency and efficiency of its management and operations. The audit's primary objective is to identify areas of strength and weakness and make recommendations for improvement.

In the aftermath of Hurricane Sandy (Sandy) in late 2012, additional legislation was enacted in July 2013 requiring modification of the OSA executed by LIPA and PSEG-LI on December 28, 2011. The majority of NorthStar's audit work was performed in the months preceding the new legislation, and as of the end of our audit period, the December 28, 2011 OSA was still in the process of being modified by the parties.[4] As a result, our findings, conclusions and recommendations are predominantly based on LIPA's operations under the National Grid/MSA model, the management and oversight of those operations exercised by the existing LIPA structure and personnel, and the OSA dated December 28, 2011. We have, however, focused our recommendations in areas where improvements are needed going forward, independent of who

[4] Modifications were still in process as of the date of the Final Draft Report.

the outside service provider is, the scope of services under a service contract, or the structure of the Authority and its governing Board.

1.2 Overview of Audit Findings and Conclusions

Throughout this management and operations audit, a number of themes emerged from our analysis that cross functional areas and represent overarching issues that will require considerable focused attention moving forward.

1. A fully contracted utility operation such as LIPA, operating without a traditional command and control structure, is critically dependent on its "utility management IQ" to be successful.

A traditional utility functions with an organizational hierarchy where decisions made at the top of the structure are communicated down the chain of command and implemented in a direct line. Communication and discussion occurs across the organization and up and down the hierarchy so that decisions based on analysis, current information, and past experience are all focused on the mission of one entity. In contrast, LIPA exists as a nucleus, separated from the realities of daily operations, information and experience by a commercial contract barrier. For a utility operating within this business model, the need for strong management skills and a deep understanding of the nuances of utility operations is of critical importance. Fundamentally it is not possible to outsource leadership for an enterprise. Thus, LIPA must possess the management skills to identify trends in performance with limited information, must know what information to seek and then evaluate that information, and must be able to relay guidance and expectations across the contract barrier to affect change in the contractor's employees. The smaller the management team, the more critical "utility management IQ" becomes, as fewer people are available to manage and direct the OSA. A fully-contracted utility must be expert in establishing and communicating expectations and effectively intervening when necessary, so expectations can become a reality.

Based on our analysis, it appears that LIPA is organized and operated from the BOT down largely as a contract administrator, without full appreciation of its ultimate responsibility to provide safe, reliable, reasonably priced electric service to the residents of Long Island. For instance:

- LIPA does not identify or manage key areas of enterprise risk including operating risks that exist within National Grid, nor does the Authority have National Grid provide operational risk assessments. As memorialized in both the MSA and OSA, as the owner of the assets, LIPA retains the ultimate responsibility for all aspects of the operations.
- LIPA does not have a comprehensive plan for provision of quality electric utility services (i.e., rates, reliability, customer service, communication) for Long Island residents. Other than the move to the OSA, LIPA does not have a long term plan for the future of the Authority.

- LIPA manages National Grid's spending (both capital and O&M) without sufficient consideration of value received for the investment. This manifests itself within LIPA in two ways: a focus on ensuring budgeted capital dollars are spent and a bias against increasing costs over current budgeted levels.

  - LIPA does not investigate project cost overruns to identify or correct problems that might arise on another project. Cost overruns are met by deferring another project.
  - There is limited interest in determining if a project cost estimate is reasonable or not. In fact, the LIPA BOT approves the total capital budget with minimal information on the projects included.
  - Improvement recommendations by National Grid, such as reducing answer times in the call center, were rejected by LIPA for cost reasons.[5]
  - LIPA's focus in reviewing National Grid's performance is limited to verifying the calculation of MSA metrics based on National Grid's data. There is no assessment of whether LIPA and its customers receive value from National Grid commensurate with the price paid.

- LIPA does not have a plan for how it can control rates over time, and while most significant decisions do include consideration of rate impacts, the focus is on not increasing rates. Absent a long term strategic plan with an associated financial strategy it is unlikely that the rate situation will change.

- LIPA does not have a system-wide continuous improvement program.

- LIPA has 95 employees, including security personnel and executive assistants, to manage a $3.6 billion (revenue) enterprise. The group responsible for T&D operations – the core service representing nearly $600 million annual expenditures – has four members, only two of whom interact with National Grid's operating personnel on a daily basis.

- The BOT Operations Committee, which is charged with overseeing and guiding the Authority's operations, was only established in 2011, and did not until very recently hold open meetings to receive information on or discuss system operations. The Committee was extensively involved in the procurement and negotiations of the OSA, power generation and fuel contracts during this period and these discussions were appropriately held in executive session.

- Until April 2013, LIPA's Executive Team had only five members (with the CFO acting as COO), and their tenure with LIPA is limited.[6]

[5] Various interviews

[6] The COO was appointed in April 2013. From December 2012 until April 2013 that role was filled by the CFO who has been with LIPA for less than two years. Only one member of the Executive Team has been with LIPA in their current position for more than five years. Only one other member of the Executive Team has more than five years with LIPA in any position. Other LIPA senior personnel have extended tenures and make valuable contributions to the management of the Authority.

The existing LIPA Management Team has done an acceptable job in running the Authority through difficult times, but has significant need of additional "utility management IQ" to be successful given its foreseeable challenges. LIPA's current structure with its focus on contract management and administration seems to have resulted in a gap in understanding by the leadership of the Authority of the depth and breadth of its of responsibility for providing electric service to Long Island.

2. **As the entity ultimately responsible for electric service on Long Island, LIPA has to keep its contractors accountable for results – all the time. The service provider contract must drive performance, allowing LIPA to exercise its responsibilities as system owner and intervene as necessary to improve performance.**

In the fully contracted business model, the "utility management IQ" discussed above, must be applied consistently and firmly. LIPA must have access to and be ready and able to apply a wide range of tools to maintain control and accountability by its contractors. Tools should include contract fees (incentives or penalties), financial (withholding of payments for services in question) or legal, but also need to include regular performance audits and collaborative techniques to convince the contractor to take action.

- Clearly, a strong, well-considered contract is essential to maintaining contractor accountability. However, it is not possible to craft the perfect contract, the perfect incentive structure, or the perfect performance metric. Particularly when addressing a dynamic operation and one where significant improvements are desired, it is essential to ensure that the contract provides for flexibility in establishing areas for performance monitoring, identifying areas where improvement is needed and setting expectations for that improvement.

- The OSA provides for some of the necessary flexibility, however additional work is needed in establishing Tier 1 targets, and developing the Tier 2 and Tier 3 metrics and targets. However, contractor control and performance cannot be fully relegated to metrics, premiums or penalties. It requires continuous guidance, diligent oversight, and meaningful intervention to ensure that things are done "right" and customer expectations are met.

- LIPA has a poor track record of dealing with National Grid under the MSA. Some of the challenges have been the result of the MSA itself, which offers only limited contractual or financial leverage for LIPA to change National Grid performance. For example, penalties under the MSA are not significant enough to change behavior and there is no incentive for National Grid to improve efficiencies. Regardless, LIPA has historically been reluctant to force change when it had the opportunity. Specifically:

- LIPA had the option to terminate the MSA when National Grid's performance in customer service allegedly fell into the penalty range for the third consecutive year.[7] Instead, LIPA renegotiated the MSA to increase the potential penalties while failing to fully enforce those previously set. This modification did not substantively change performance incentives or set penalties at levels to influence performance for National Grid.
- LIPA has repeatedly accepted National Grid's requests for force majeure relief from contract penalties.

- The Authority relied on National Grid to conduct internal audits of its (National Grid's) performance, but due to reasonable concerns regarding the quality of audits and access by LIPA to the underlying data, LIPA elected to not use the National Grid Internal Audit service included in the MSA over the past three years.[8] LIPA contracted to have some audits of National Grid conducted by an outside firm. These focused on auditing the calculation of the performance metrics and a few small control issues. The metric audits for 2010 and 2011 remained incomplete until late 2012, and LIPA did not invoice National Grid for penalties until mid-2013. The 2012 metric audit has not been completed. LIPA only established an internal audit function in late 2012, staffed with one auditor. The initial internal audit plan prepared in May 2013 did not include any audit topics of the service provider.

- Other challenges for LIPA's management of the MSA were reportedly due to National Grid's reluctance to be open with LIPA on operational issues.[9] LIPA has had significant challenges in obtaining access to information regarding the cost to operate the LIPA system. Under the MSA LIPA is not given access to that information because the costs are included in the fixed fee. LIPA has no information on the compensation structure of the National Grid Long Island employees, typically does not know where National Grid staff performing LIPA services report within the National Grid corporate structure, and in some situations LIPA is not provided the names of the people providing services.[10] However, some LIPA functions have established close and successful collaborations across the contractual barrier.

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[7] LIPA alleged, and National Grid refuted, that National Grid failed to meet the customer service metric in the third year, and was in default of the MSA for failing the metric three years in a row. However, the parties ultimately settled the dispute without National Grid admitting the failure, which resulted in the Settlement Agreement and Second Amendment.

[8] Various interviews

[9] Various interviews

[10] LIPA did not have any form of organization charts with names showing where LIPA support functions were within National Grid; National Grid refused to supply this information in response to a data request, citing that the MSA did not require it.

3. **LIPA's customers deserve to be treated with maturity and respect, to receive accurate and timely information about system operations, rates and performance, and to have appropriate levels of service.**

LIPA's current customer satisfaction situation is critical and cannot be ignored. Gaining respect from customers will not happen quickly and will not happen solely as a result of infrastructure investments or a change in service providers. LIPA needs to take direct responsibility for customer service and needs to be integrally involved in its improvement. Although LIPA's system is operated by a contracted service provider, ultimately the responsibility for providing electric service to the customers is LIPA's, not National Grid's or PSEG-LI's.

- Customers that have direct contact with National Grid (e.g., a customer that calls the call center) consider the service to be adequate; however, LIPA's performance in perception-based customer satisfaction surveys such as JD Power is extremely poor. LIPA also suffers from generally negative media coverage.

- While LIPA disseminates a great deal of information to customers and stakeholders, it struggles to communicate the right things in the most effective manner. As of mid-2013, LIPA had not set expectations for the upcoming storm season[11] or the transition to PSEG-LI; rate communications can be and have been confusing; and LIPA has not successfully explained existing levels of debt and the debt financing process, the role of debt in the provision of reliable power and service, or the impact of debt on rates.

- Many aspects of the MSA shield LIPA from customer service issues, or worse, promote poor customer service. A number of MSA customer service performance targets − and actual performance − are below industry standards and have been for some time. Many customer contact problems do not come to LIPA but stay at National Grid, and most issues are to be resolved by National Grid. In some cases, LIPA may have conditioned its customers to expect relatively low service levels.

- Recent organizational changes serve to dilute the focus on the customer and customer service issues. There is no single point of LIPA contact responsible for improving customer service or serving as the "voice of the customer." In response to the departure of LIPA's VP Customer Service following Sandy, the customer service and communications functions were distributed throughout the organization. Thus, customer service has lost the visibility previously associated with a VP-level position.

- The employees currently involved with day-to-day operations and customer interface will be the same individuals under PSEG-LI. At the time audit field work was completed, PSEG-LI had few defined plans for changing customer perception or addressing the culture change necessary to foster improved customer interactions and perceptions using the existing workforce. PSEG-LI is presently developing numerous improvement initiatives in the customer service function. While initiatives intended to improve call

[11] During fact verification, LIPA indicated that communication with municipalities has begun.

center operations will help with customer perceptions, they alone are not sufficient to change internal culture. Culture change takes commitment and time.

While NorthStar identified numerous recommendations to improve the customer service and communications areas, establishing a customer focus with accountability and responsibility for the customer experience within the LIPA Management team is a critical part of achieving performance in this area.

4. LIPA cannot become subordinated to the service provider's core utility operations.

- The audit revealed numerous areas where National Grid's Long Island operations were not treated with the same level of management attention as that shown in National Grid's NYS electric operations.[12] National Grid's Long Island personnel were not aware of management tools routinely used elsewhere in National Grid's operations. The Long Island operations were not part of continuous process improvements or productivity incentive programs elsewhere in Grid's operations.

- The lack of focus and attention on LIPA's operations can be attributed to a number of factors, from contractual to corporate culture. For LIPA services and operations to improve on a continuous basis, LIPA operations and LIPA customers must remain as important to PSEG executive management at the corporate and Board level as its New Jersey operations and customers. LIPA selected PSEG/PSEG-LI as its new service provider in large part based on its reputation for operations, reliability and customer service in New Jersey.

- LIPA and its BOT must become and remain key stakeholders in PSEG's management and planning, so that LIPA will be afforded the opportunity to share in the benefits of the experience and enviable success that PSEG has achieved in New Jersey.

5. The Authority deserves to receive outstanding performance from its providers and should only pay premiums for performance above the current norms.

LIPA selected PSEG with an expectation that PSEG-LI would improve LIPA's performance through focused application of management skills, processes, controls, and management tools. In short, in selecting PSEG, LIPA seeks to provide to its customers the same high level of service and performance as enjoyed by PSEG customers in New Jersey.

For this reason and to guarantee that LIPA continues to be of key importance to PSEG, LIPA should not pay premiums to PSEG-LI for performance already demonstrated on Long Island or continue to pay premiums once acceptable performance levels are achieved. Performance premiums should be paid for just that, performance higher than the norms, significant performance improvements and performance above standard expectations.

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[12] Comprehensive Management Audit of Niagara Mohawk Power Corporation d/b/a National Grid Electric Business, Case 08-E-0827, Final Report: December 4, 2009.

To measure performance as worthy of premium payments, appropriate performance expectations must be established. For LIPA and PSEG-LI, the tool to do this is the performance metrics envisioned in the OSA. Effective management under LIPA's business model requires a measurement system, and a commitment to continuous improvement that is greater than for typical utilities because of the disconnect and counter incentives inherent in contracting.

The OSA incorporates some changes intended to address the challenges experienced by LIPA in managing National Grid through the MSA. The MSA was not structured in a manner that encouraged National Grid to improve its performance in operating the LIPA system, and the penalties were not of sufficient magnitude to provide a deterrent to lackluster performance. A fixed fee form of payment with no ability to review actual costs incurred allows the service provider to reduce the level of service, and encourage capital expenditures (which are reimbursed) rather than maintenance expenses (which are covered by the fixed fee). The OSA replaces the penalties and fixed fee structure of the MSA with a more sophisticated program of incentives and penalties, and makes both O&M expenditures and capital projects subject to budget approval by LIPA and reimbursement at cost. The management fee earned by PSEG-LI is separate from the costs of operating the system.

The system of metrics envisioned in the OSA provides some improvement over those in the MSA. However, the work of establishing the targets for the Tier 1 metrics (tied to the incentive/penalty calculation) is still in process and Tier 2 and Tier 3 metrics are still under development. It is critical that LIPA continue to have the ability to modify the metrics over time, allowing it to direct PSEG-LI's focus and assure that satisfactory performance in one area does not suffer as resources are applied to improving performance in other areas. It is not possible to develop the ultimate set of metrics for all situations − particularly not in an industry that is constantly evolving and for a utility operation where significant improvements must be obtained. Such flexibility is appropriate and essential.

The process of identifying and defining appropriate and sufficient metrics to assure that LIPA receives at least the same level of service and performance as PSEG's own customers will not be easy. LIPA has only limited experience with using benchmarking to set performance metrics, and establishing targets based on LIPA's current performance would not achieve the Authority's expectations of a higher level of service in selecting PSEG-LI as its new service provider. Instead, the performance metrics and targets should be in line with those used by PSEG to drive its performance in New Jersey or based on established industry benchmarks as independently identified.

The establishment of metrics and targets does not, on its own, guarantee LIPA's customers will see the benefits of PSEG-level service and performance. LIPA must make decisions consistent with its ultimate responsibility for the system and its customers, performance of the service provider must be monitored and validated, and the range of other processes and controls available to LIPA for ensuring a high level of service must be used to promote the long term interests of the Long Island ratepayers.

6. **Functional areas where LIPA is performing well should be preserved and supported through the transition to PSEG-LI and the ServCo model.**

With so much that must be improved, it is equally important to highlight and preserve the performance of functions that are performing well. NorthStar identified three major areas where the current processes and operations are performing well:

- **System Maintenance and Reliability** – LIPA's system reliability performance ranks high among New York electric utilities with mostly above-ground facilities (see **Exhibit 1-1)**. This function is performed within National Grid's Long Island organization.[13] Under the new ServCo model, these groups are shown as remaining in the same basic structure.

Exhibit 1-1[14]
Five Year System Average Reliability Indices in New York (2008 – 2012)

Utility	Excluding Major Storms		Including Major Storms	
	SAIFI	CAIDI	SAIFI	CAIDI
Central Hudson Gas & Electric	1.22	2.35	2.19	8.74
Con Edison (radial system data)	0.40	1.93	0.78	22.07
Long Island Power Authority	0.73	1.21	1.23	7.40
New York State Electric and Gas	1.10	2.03	1.94	7.27
Niagara Mohawk (National Grid)	0.86	1.97	1.19	3.30
Orange and Rockland Utilities	1.07	1.72	1.71	11.92
Rochester Gas & Electric	0.73	1.80	0.97	2.60
Statewide[15]	0.57	1.89	0.91	8.86

Source: NYPSC 2012 Interruption Report

- **System Planning** – LIPA does a good job of planning for system growth and stability. Given the large amount of small renewable installations (e.g., roof-top photovoltaic (PV) systems) analysis of system stability is of critical importance. Strong system planning also contributes to the high reliability numbers.[16]

- **Power Supply Procurement and Management** – LIPA's current systems for load forecasting and planning, and procuring and managing its energy and capacity supply are very good. This function is performed by a strong collaboration between LIPA, National Grid for analysis and CEE as the power (and now fuel) manager.[17]

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[13] See Chapter 9 – System Planning, Chapter 12 – T&D Operations and Maintenance and Chapter 13 – Work Management.
[14] Reproduction of Exhibit 9-2 from Chapter 9 – System Planning.
[15] Includes Con Edison total Network and Radial systems for state averages.
[16] See Chapter 9 – System Planning.
[17] See Chapter 17 – Long Term Energy Supply Planning, Chapter 18 – Power and Fuel Supply Management, and Chapter 20 – Regional Power Markets.

1.3 Summary of Recommendations

This report contains a total of eighty-three recommendations that are summarized below. Detailed findings and conclusions supporting the recommendations are provided in each of the related chapters. The chapters also contain additional details regarding many of these recommendations and should be relied upon to develop implementation plans.

It is important to note, as indicated above, that NorthStar's audit conclusions and recommendations are based on LIPA's operations under the National Grid/MSA model, the management and oversight of those operations exercised by the existing LIPA structure and personnel, and the OSA dated December 28, 2011. We have focused our recommendations in areas where improvements are needed going forward, with limited knowledge of how the LIPA Reform Act and revisions to the OSA will alter LIPA roles and responsibilities, and how the recommendations will ultimately be implemented and by whom.

In this regard, it is recognized that given the enactment of the LIPA Reform Act, and the revisions to the OSA contemplated as a result thereof, the recommendations summarized in the two exhibits below are distinguished between those which we believe LIPA can adopt and cause to be implemented directly – see **Exhibit 1-2**, and those that LIPA can recommend be adopted and implemented by PSEG-LI – see **Exhibit 1-3**.

LIPA's acceptance or rejection of NorthStar's recommendations should be made on the basis of each recommendation's merit for improving performance, overall cost of service and customer service. For those recommendations more directed from LIPA to the service provider, PSEG-LI should consider these recommendations for improvement in the same light.

Exhibit 1-2
Summary of Recommendations for LIPA Implementation

Rec #	Recommendation
4.4.1	Actively recruit and retain personnel with a strong understanding of all aspects of utility operations, including T&D field activities, customer service functions, capital project management, and rates and regulatory activities. As the entity ultimately responsible for the delivery of electric power to Long Island, it is essential that the knowledge base and competencies within the organization reflect the totality of the organizations responsibilities to its ratepayers.
4.4.2	Develop a Monthly Operating Report (in conjunction with PSEG-LI) to provide the LIPA Executive Team and BOT with the key information from the entire organization's activities needed for oversight and control, with additional supporting information available if needed. The presentation should be in a format that is easily understood and should include a true analysis of the causal factors, trends and risks arising from performance data.
4.4.3	Develop a formal process for evaluating the performance of LIPA Executive management which includes defined goals and performance targets (tied to the mission and objectives), and involves the BOT and Personnel and Compensation Committee in the development of the goals for, and the evaluation of, executive management performance.
4.4.4	Develop employee performance goals which tie to the comprehensive performance management system and are reflected in the employee performance evaluation process.
5.4.1	Work with appropriate agencies and officials to encourage maintenance of the Board at full strength and to identify candidates for the Board with experience with larger corporations and energy or utility companies.
5.4.2	Improve the BOT Committee coverage of Authority functions currently not covered. For example, specific Committees should have responsibility for long term strategic planning, enterprise risk management, traditional environmental concerns and activities at the former Shoreham site. Through Trustee orientation and training, and with direction from Board Chair, encourage all Committees to regularly review each of the Authority functions included in their charter scope.
5.4.3	Explore options for enhancing communication with the public regarding BOT activities, including mechanisms for providing response to public comments.
5.4.4	Develop a proactive strategy to guide the BOT in recruiting, retaining, and developing LIPA Officer-level personnel.
7.4.1	Undertake a comprehensive, coordinated enterprise risk assessment study (in conjunction with PSEG-LI) that covers all aspects of the provision of electric service, regardless of what entity performs the function. The study should include industry recognized tools and processes for evaluation of the magnitude and likelihood of risk events, leading to the development of a prioritization of risks and the development of appropriate risk mitigation strategies commensurate with the risk of loss and the cost to mitigate. Develop processes to maintain and regularly update the risk assessment.
7.4.2	Develop (internally or with contractor assistance) a strategic plan to address the totality of the provision of electric service to Long Island, based on a comprehensive assessment of, for example, the needs and risks associated with the service territory, its customers, fiduciary obligations, and market impacts and uncertainties. The strategic plan should include identification of strategies to achieve the goals of the plan and measurement of progress. With the plan in place, prioritization and evaluation of on-going and proposed new programs and initiatives, capital projects and other major decisions should be considered and evaluated in the framework of their support for the long term plan.

Rec #	Recommendation
7.4.3	Develop a comprehensive set of corporate performance measurements (in conjunction with PSEG-LI) that are consistent with requirements of PARA, tied to the formal Enterprise Risk Management program and Strategic Plan, and include, as appropriate, performance of relevant service providers.
7.4.4	Strengthen the capabilities and commitment to Internal Audit within the Authority, including dedicating personnel with utility operations and auditing experience. Under the OSA, the need for qualified Internal Auditors who are able to develop an understanding of the details of the OSA agreement and other key service agreements will be critical to LIPA being able to effectively control and ensure compliance of the service providers.
8.4.1	Recommend the adoption by PSEG-LI of all recommendations in this audit that are within the scope of PSEG-LI's contract (as identified in Exhibit 1-3), development of implementation plans and strategies to achieve the recommendations in a timely manner, and that the BOT be provided with quarterly written updates on progress towards achieving implementation.
8.4.2	Recommend to the DPS that an evaluation of the implementation of all recommendations contained in this report be performed in the next management audit.
8.4.3	Within the first year of the OSA, conduct (internally or with contractor assistance) a thorough, technical review of the OSA metrics (Tiers 1, 2 and 3) to fully document the basis for the metrics, key drivers and relationships, leading/lagging nature, benchmarks and performance at other utilities, and possible data and reporting issues. Develop a process for monitoring industry trends and regular updating of benchmarks and comparable performance for comparison with PSEG-LI performance.
8.4.4	Develop performance measures for emergency response and include them in a future revision of the OSA or its metrics.
8.4.5	Significantly improve LIPA's in-house internal audit capabilities. Strengthen the reporting relationship and communications between the Director of Internal Audit and the Finance & Audit Committee of the BOT. Develop the Internal Audit annual audit plan based on the enterprise risk assessment. Obtain access, in conjunction with PSEG-LI, for LIPA's Internal Audit group to appropriate records and documents within the ServCo and PSEG-LI organizations.
11.4.1	Conduct a detailed review of proposed capital projects and expenditures with the BOT as part of the capital budget approval process. Provide actual capital expenditure updates to the BOT on project- and program-specific bases.
11.4.2	Conduct a formal analysis to determine the appropriate level of cash reserves, that, at a minimum, considers potential changes in cash requirements due to the restructuring of the recent FPPCA, pre-funding requirement related to the OSA operating account, exposure to post collateral in connection with energy risk management financial hedging activities, transition from the MSA fixed O&M expenses billed on a predetermined monthly percentage to a variable expense pass-through by PSEG-LI to LIPA and that addresses the FEMA reimbursement impacts.
11.4.3	Develop and adopt a formal set of policies and procedures for maintaining compliance with provisions of the Internal Revenue Code regarding tax-advantaged bonds and notes, including the process for reimbursing capital projects with bond proceeds.
11.4.4	Update the Investment Guidelines provided to LIPA's Investment Manager(s) to include instructions for investing proceeds from tax-advantaged bonds as it relates to potential Internal Revenue Code arbitrage yield restrictions and rebate requirements.
11.4.5	Perform an internal audit of debt management activities to ensure compliance with bond covenants and provisions of the Internal Revenue Code pertaining to tax-advantaged bonds.

Rec #	Recommendation
11.4.6	Make revenue increases embedded in LIPA's proposed five-year Statements of Revenues and Expenses transparent to the Board of Trustees and Public during the annual budgeting cycle.
11.4.7	Enhance LIPA's internal financial planning capability and software tools and transition the long-term financial planning function from Navigant to LIPA.
14.4.1	Designate or add a senior/executive level position, reporting to the COO, with oversight responsibility for, and experience in, customer operations and communication.
14.4.3	Develop a Customer Service Strategic Plan (in conjunction with PSEG-LI), including establishment of a formalized approach to customer service performance improvement.
14.4.5	Ensure a process is in place, either within LIPA or delegated to another party, to handle external, executive and escalated customer complaints (those that elevate outside of the call center), similar to the process specified in the current LIPA Tariff, and that includes benchmarked specific case resolution service level standards.
15.4.1	Immediately develop and implement a communications strategy and message to set customer expectations for the upcoming storm season. Communications should address outages, outage management systems, and storm response/restoration processes and the roles of LIPA, National Grid, and PSEG-LI for this season.
15.4.3	In conjunction with PSEG-LI, immediately begin to implement the Transition Communications Plan, to inform customers and stakeholders of expected changes and to manage expectations regarding the speed of change and how change will be enacted given the same workforce and existing processes.
15.4.7	Consider adding a communications metric(s) in a future revision of the OSA or its metrics.
15.4.8	Improve communication of rate and tariff changes, in conjunction with PSEG-LI's communication and customer service functions.
15.4.9	Improve the discussion of the bill on the LIPA website and in bill inserts, in conjunction with PSEG-LI's communication and customer service functions.
15.4.10	Improve the information, links and visibility of BOT meetings, minutes and related documents and resources on LIPA's website.
16.4.1	For the current (2013) storm season, develop procedures to address lessons learned from Sandy, including: expedited implementation of storm hardening initiatives; plans for handling increased call volumes, possible failure of the call center and possible flooding of LIPA assets; interim improvements to address deficiencies in the ETR process; confirmation of responsibility for storm communications and commitment to follow the communications plan; and provision of shelter lists and guidance to customers responding to broader system conditions caused by flooding, such as inspecting customer premises and authorizing the reenergizing of homes and businesses.
17.4.1	Contract for an independent evaluation of the actual effectiveness and achievements of the current energy efficiency initiatives and programs, including verification of energy and capacity savings actually achieved in field installations, and assess the reasonableness of future ELI goals given current market penetration and overall market trends.

Rec #	Recommendation
17.4.2	Prepare, or cause PSEG-LI to prepare, a new or updated ERP that addresses the entire resource plan needed to meet future energy supply needs for Long Island, including realistic, economic assessments of traditional generation, innovative commitment opportunities, renewable resources, and the results of the energy efficiency evaluation, while recognizing the need for flexibility to respond to and take advantage of opportunities and changing market and technological conditions. This plan should be available to the public and provide a general guideline for resource decisions and a benchmark against which to measure achievements and progress towards all of the planning goals.
17.4.3	Provide periodic (annual) updates to the BOT, in conjunction with PSEG-LI, on progress towards and changes in the energy resource plan, including status reports on progress towards efficiency, renewables and GHG goals.
18.4.1	Establish, or cause to be established, the performance metrics associated with the penalty clauses in the FMA, based on data such as external benchmarking and desired improvements in performance. The metrics should focus on performance that will provide benefits to ratepayers through encouraging least cost fuel procurement. Pricing metrics should be tested against past data (e.g., from the EMA period) to verify appropriate results and adequate penalties to preclude poor performance.
18.4.2	Improve, or cause to be improved, the documentation and reporting on fuel oil purchases under the FMA. Review existing processes for fuel oil procurement and management and propose modifications and improvements to bring the procedures related to fuel oil planning and purchases to a level commensurate with those in place for natural gas purchases.
18.4.3	Contract for an independent analysis comparing LIPA's energy risk management program to those at other utilities, and evaluate the benefits to ratepayers compared to the cost of the program, including option premiums and fees paid. The analysis should include whether similar price volatility reductions could be achieved at a lower cost through a less sophisticated program.
18.4.4	Include at least one aspect of the power supply management functions in the Internal Audit plan every year, so that over time IA would review the management of the power supply contracts, fuel procurement activities, near-term power system management, the middle office monitoring program, and the energy price risk hedging program.
19.4.1	Finalize the draft "Plan of Administration of Calculation of the FPPCA" and include better documentation concerning data flows, the calculation verification process and the responsibilities of the various organizations.
20.4.1	Determine the impact of the current vacant position in the Power Markets Policy group on the achievements of the group at NYISO, and identify options for maintaining appropriate monitoring and participation in the NYISO and other regional power markets to protect LIPA's long-term power interests.

Exhibit 1-3
Summary of Recommendations for PSEG-LI Implementation

Rec #	Recommendation
9.4.1	Develop a minimum five-year system plan – an investment model optimizing capital investment in the LIPA transmission and distribution system.
9.4.2	To the extent practical the system planning function should justify capital improvement projects based on cost/benefit analysis in addition to engineering needs analysis.
10.4.1	Adopt PSE&G's Project Management "Playbook" as a baseline for managing capital projects.
10.4.2	Develop formal capital project management policies and procedures that support the Project Management Playbook.
10.4.3	Define deliverables required for each project phase and establish criteria for completing each project phase. Include all elements of a project life cycle from planning to closeout.
10.4.4	Define project management performance measures focusing on the effectiveness of cost estimation and scheduling. Cost estimates and schedules developed for preliminary plans should be evaluated when a project is complete to determine where further enhancements to project estimating can be made.
10.4.5	Utilize a Work Breakdown Structure (WBS) in the initial phases of the project justification and conceptual estimating, and continue their refinement as the project progresses.
10.4.6	Address the deficiencies in project estimating by making organizational and process improvements and creating a capital project estimating function/organization equipped with appropriate tools.
10.4.7	Develop a capital project cost forecasting/trending capability.
10.4.8	Incorporate contingency management in capital project cost estimating and cost management.
10.4.9	Formalize capital project change order management controls.
10.4.10	Improve periodic capital progress reporting.
10.4.11	Improve capital project document control.
10.4.12	Perform capital project schedule management.
12.4.1	Increase the effectiveness of the vegetation management program by further refining analysis of tree-related reliability.
12.4.2	Develop and implement a rigorous procedure that requires a thorough analysis and direct comparison of the costs of repairing versus replacing T&D system equipment. While other factors, such as system reliability, should be analyzed as well, LIPA should be aware of the cost-effectiveness of each project or program, and the impact it will have on customer costs.
12.4.3	Establish an asset management model that supports the LIPA T&D preventive maintenance program.
13.4.1	Develop an integrated work management system that formalizes planned work, support requirements, and provides continuous feedback on workforce effectiveness.
13.4.2	Fill gaps in the current management information reporting and organizational reporting relationships to support an integrated work management system.
14.4.2	Develop improved service levels and service level standards throughout the customer service organization, both operational and OSA-level.

Rec #	Recommendation
14.4.4	Develop a more analytical approach to the management and evaluation of customer service functions, including collections, that allows for analyses of trends and casual effects, and includes the associated reporting.
14.4.6	Develop and implement a plan to address the backlog of billing exceptions.
14.4.7	Conduct a detailed cost-benefit analysis of a switch to monthly meter reading and discontinuation of the process of bi-monthly estimating, particularly in light of the switch to a monthly power supply charge.
14.4.8	Establish a more formalized rate applications process to improve customer service by evaluating customer rate assignments. Specific activities would be the development of a set of analysis tools to model customer usage across rates, physical inspection of customer facilities, and outreach to customers after analysis is conducted.
14.4.9	Replace CAS within the next five years per the schedule proposed by PSEG-LI.
15.4.2	Immediately develop a plan for addressing the culture changes and re-education necessary to ensure the existing National Grid work force fosters and promotes the same values as espoused by PSEG.
15.4.4	Develop a comprehensive, coordinated communications, government and public affairs strategy and associated policies/procedures.
15.4.5	Communicate issues of significance to customers regularly and in a timely manner.
15.4.6	Consolidate the communications and government affairs functions.
16.4.2	Review and update as necessary, procedures to adequately address the possibility of flooding in areas that may be affected by future storms or emergencies. The procedures should include not only preventive measures, but should also provide guidance for responding to broader system conditions caused by flooding, such as inspecting customer premises and authorizing the reenergizing of homes and businesses.
16.4.3	Review and update as necessary, the business continuity plan to include failure of the call center due to or during a major storm event.
16.4.4	Ensure the ERIPs accurately reflect the responsibility for storm communications.
16.4.5	Continue to expedite the implementation of storm hardening initiatives identified based on prior storm lessons learned, including Sandy.
16.4.6	When under emergency conditions, consistently follow the communications plan and provide customers with regular updates (including press conferences) even if limited information is available.
16.4.7	Implement appropriate improvements to address deficiencies in the ETR process for future storm seasons.
16.4.8	Implement remaining outstanding open recommendations identified in the DPS Audit of LIPA/National Grid's Hurricane Irene Response and issues identified in the Sandy After Action Report. Develop a formalized process for tracking implementation progress.
16.4.9	Develop more robust plans for handling the call volumes possible during a major storm.
16.4.10	Review and update as necessary, processes, processes to provide shelter lists to the call center representatives when under emergency conditions to assist customers that may not have the capability to contact FEMA.
17.4.4	Assess the value of continuing LIPA's Load Research program, and investigate the potential value to forecasting and energy efficiency program development of periodic residential and commercial appliance saturation and end use surveys.
17.4.5	Maintain, to the extent possible, the current energy supply planning processes, resources, organization, and tools under the ServCo model. Changes to the planning process should demonstrate a strong likelihood of significant improvement in efficiency or results.

2. AUDIT APPROACH

This management and operations audit provides a unique opportunity to gain valuable insight into LIPA's operations and management. The audit has been conducted in a constructive manner, characterized by frank and open discussion of findings, conclusions and recommendations. NorthStar's final report provides a comprehensive, independent and objective evaluation of current performance, specifically with respect to LIPA's construction program planning, system operations, fuel and purchased power and provides recommendations for performance improvements.

2.1 Scope, Objectives and Audit Timetable

This management and operations audit was authorized by the Long Island Power Authority Oversight and Accountability Act (the LIPA Act) which was signed into law on February 1, 2012. The LIPA Act requires LIPA to undergo periodic audits of internal policies and procedures to improve transparency and efficiency of its management and operations. The audit's primary objective is to identify areas of strength and weakness and make recommendations for improvement.

The audit was undertaken from April through June 2013 as the LIPA management structure was in transition from National Grid – Long Island under the Management Services Agreement (MSA), to Public Service Enterprise Group (PSEG) Long Island LLC (PSEG-LI) under the Operating Services Agreement (OSA) executed on December 28, 2011. In the aftermath of Hurricane Sandy, in July 2013, NYS enacted legislation modifying the OSA as executed by LIPA and PSEG-LI on December 28, 2011. NorthStar's audit work was performed in the months preceding the new Legislation, and as of the end of our audit period, the details of changes to the OSA were still under consideration. As a result, our findings, conclusions and recommendations are based on LIPA's operations under the National Grid/MSA model, the management and oversight of those operations exercised by the existing LIPA structure and personnel, and the OSA dated December 28, 2011. Nevertheless, our audit assesses LIPA's efficiency and effectiveness in meeting its mission, particularly with respect to meeting its performance goals and the extent to which there are opportunities for improvement. This is especially important in light of the transition to a new business model and new OSA.

As indicated in the RFP, NorthStar's audit proposal and the Final Approved Work Plan, the audit scope is comprehensive, focusing on LIPA's operations and management, including the Authority's duty to set rates at the lowest level consistent with standards and procedures provided in Public Authorities Law (PAL) §*1020-f(u)*. As set forth in the establishing legislation,[1] the audit addresses:

- The Authority's construction and capital program planning in relation to the needs of its customers for reliable service;

[1] The LIPA Act, Section 3, which amends the Public Authorities Law, Section 1020-f.

- The overall efficiency of the Authority's operations;
- The Authority's Fuel and Purchased Power Cost Adjustment clause and recovery of costs associated with such clause;
- The Authority's annual budgeting procedures and process.

NorthStar was directed by the DPS to delete two topic areas from its initial proposed audit scope:

- The manner in which the Authority is meeting its debt service obligations.
- The Authority's compliance with debt covenants.

The scope of work, described with greater specificity in NorthStar's Final Approved Work Plan, addresses the issues of:

- Purpose, mission, planning, goals and objectives, and strategies,
- Functions, processes, practices, and systems,
- Organizational design,
- Staffing, responsibilities and accountabilities,
- Cost control/cost oversight,
- Efficiency and effectiveness,
- Results and performance, and
- Opportunities for improvements, including "best practices" (based on past experience) that are appropriate to LIPA's operating environment.

NorthStar addressed a broad scope of utility functional areas based on evaluative criteria specified in the RFP, additional recommended evaluative criteria, and the numerous tasks associated with each audit area in the Work Plan - Areas and Issues. We examined operating conditions as they existed, with significant focus on how LIPA is managing the change control process as it makes the transition to the new OSA with PSEG-LI. We reviewed changes/improvements made to the existing MSA as it was changed to the OSA, and how that transition is being managed. The audit identified and addressed gaps and recommended improvement opportunities that will benefit LIPA's ratepayers as this new management relationship develops.

2.2 Methodology

NorthStar prides itself on performing independent and objective management audits for regulators. In this context, we planned and conducted the audit to maximize DPS Staff participation, and worked closely with the DPS project manager and LIPA throughout the engagement.

The RFP and proposal identified a time schedule for the audit assuming a start date of October 8, 2012, submission of a draft report in July, 2013 and final report on or before August 2, 2013. The audit schedule was delayed and field work did not begin until April 2013, was conducted for a period of three months, and was followed by submission of the draft report on August 2, 2013. The Final Draft Report was submitted on September 9, 2013, and the Final Report on September 13, 2013.

The audit was conducted in three phases:

- Phase I. Orientation and Planning
- Phase II. Technical Review
- Phase III. Report Development

Phase I. Orientation and Planning

The objectives in the first phase of the audit were to confirm our understanding of the audit objectives and scope and the DPS' expectations from the audit; finalize contractual, project management and other administrative matters; perform preliminary data collection; and develop and obtain approval of our detailed work plan which guided our activities during the remainder of the audit. Work activities included in this phase are listed below.

- Complete logistical and contractual arrangements with DPS Staff and LIPA. Specifics regarding project logistics, key contacts, interfaces, schedules and communications were established as well as agreement on protocols for the audit, including the following:
  - Procedures for requesting and tracking interviews and documents.
  - Working paper and documentation requirements.
  - Procedures for adhering to auditing standards.
  - Policies and procedures for treating confidential information.
  - Quality control and reporting procedures.
- Meeting with DPS Staff to discuss any concerns regarding LIPA and any additional issues or areas to be considered, and further explore the Staff's objectives for the audit.
- Reviewed responses to our initial document requests.
- Prepared our final work plan and obtained DPS approval. The work plan was approved on March 22, 2013 and included detailed evaluative criteria; tasks, activities, consultant assignments and hours; and a revised audit schedule.

Phase II. Technical Review

In this phase, the audit team performed its principal investigation, data collection and other technical review activities for each of the audit elements. In general, our audit tasks and activities included the following:

- Review and analysis of documents and other data requested from LIPA.
- Interviews with LIPA, National Grid, PSEG-LI, CEE, various consulting firms retained by LIPA, and other appropriate personnel operating on behalf of LIPA.
- Testing compliance with Authority, industry and other standards.

NorthStar's audit activities included 908 information requests and 185 interviews. In formulating conclusions, the audit team focused on substantive issues. LIPA management practices were evaluated against existing rules and regulations as well as sound, generally accepted business practices. We applied a standard of reasonableness which regulators and courts have accepted in a wide range of evaluations of management performance, that is, one that does not require perfection, is not based on outcomes, and does not rely on hindsight. The audit conclusions reflect areas where LIPA is appropriately managing as well as areas where improvement is required.

Phase III. Report Development

Upon completion of the audit field work and analyses, NorthStar prepared draft and final reports. A preliminary draft report was prepared and submitted to the DPS project manager for review and comment on July 30, 2013. The report included an executive summary, a description of the audit process, and completed chapters that addressed each of the audit topic areas. Each of these focused chapters included an overview, evaluative criteria, findings, conclusions and recommendations. Based on feedback from the DPS Staff and fact verification by LIPA, NorthStar prepared and submitted a Final Draft Report to the DPS project manager September 9, 2013.

2.3 Organization of the Report

This report is comprised of 20 chapters, including an Executive Summary and this chapter with an overview of NorthStar's approach to the audit.

Chapter 3 – Background on LIPA provides a discussion of the history and development of LIPA and its unique organizational structure and operating model. LIPA is not organized like a typical electric utility and in order to understand the conclusions and recommendations of this audit, it is essential that the reader have an understanding of this unique operating model. This chapter provides that context from which the audit findings, conclusions and recommendations are derived.

The technical chapters are grouped into three major sections by focus: Executive Management, System Operations, and Power Supply Management.

The first group of chapters addresses LIPA's organization and overall executive management. In general, the topics and functions addressed in these chapters are under LIPA's direct control and are executed by LIPA personnel. The chapters in this section are:

4. LIPA Organization and Executive Management
5. Board of Trustees
6. Contract Management and Performance Measurement
7. Enterprise Risk Management and Strategic Planning
8. Transition and Management of the ServCo/OSA Organization

The second group of chapters addresses LIPA's system operations, areas that are primarily performed by National Grid under the MSA and over which LIPA has limited direct control. The chapters in this group are:

9. System Planning
10. Capital Program and Project Planning and Management
11. Capital and O&M Budgeting

12. T&D Operations and Maintenance
13. Work Management
14. Customer Service
15. External Communications
16. Storm Communications and Response

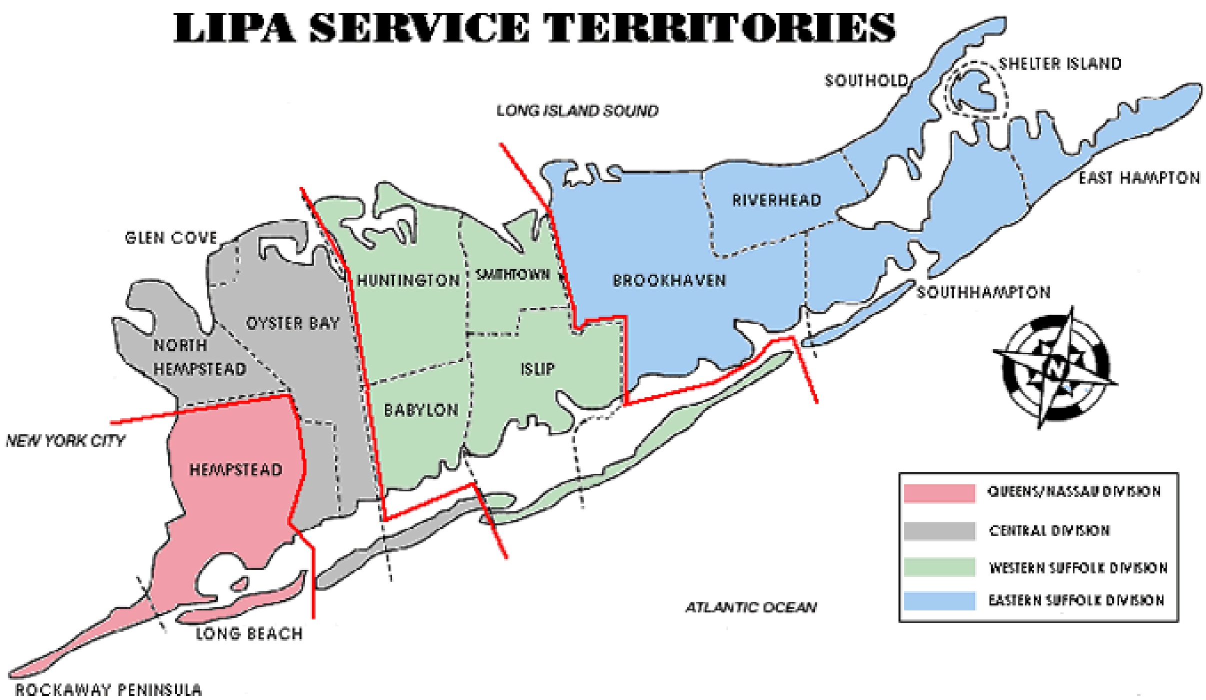
The third group of chapters focuses on the management of LIPA's power supply. These functions are mostly under LIPA's control, with their actual execution outsourced through several contracts and with National Grid providing certain analytical support under the MSA. The chapters in this group are:

17. Long-Term Energy Supply Planning
18. Power Supply and Fuel Management
19. LIPA's Fuel and Purchased Power Cost Adjustment Clause
20. Regional Power Markets

3. BACKGROUND ON LIPA

LIPA is a corporate municipal instrumentality and political subdivision of the State of New York authorized under the Long Island Power Authority Act of 1985 (the Act). LIPA provides retail electric service to approximately 1.1 million customers within its service area, which is illustrated in **Exhibit 3-1.** LIPA is the 2nd largest municipal electric utility in the nation in terms of electric revenues, 3rd largest in terms of customers served and the 7th largest in terms of electricity delivered.[1] During 2011, the maximum annual peak demand experienced by LIPA totaled approximately 5,771 megawatts (MW), inclusive of sales for resale. LIPA's total annual revenues during 2011 approximated \$3.689 billion, of which over \$3.661 billion was derived from retail electric sales.[2] Approximately 54 percent of LIPA's revenue comes from residential sales, 44 percent from commercial customers, and the balance from sales to public authorities and municipalities.[3]

Exhibit 3-1



The Authority became the retail supplier of electric service in most of Nassau and Suffolk Counties and the Rockaway Peninsula of Queens County on May 28, 1998, by acquiring the Long Island Lighting Company (LILCO) as a wholly owned subsidiary of the Authority.

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[1] www.lipower.org

[2] Biennial Report of the Consulting Engineer and Rate Consultant for the Period January 1, 2010 through December 31, 2011.

[3] Financial Statement, 2011, p. 24.

Before the LIPA/LILCO Merger, LILCO was a publicly traded, shareholder-owned corporation that, since the early 1900s, was the sole supplier of both retail electric and gas service in the Long Island service area.

The Long Island Power Authority owns the following assets:

- An electric transmission and distribution system (the T&D System) serving most of Nassau and Suffolk Counties and the Rockaway Peninsula of Queens County, including assets, facilities, equipment, and contractual arrangements used to provide the transmission and distribution of electrical capacity and energy to electric customers within the Service Area
- An 18 percent ownership interest in the Nine Mile Point 2 Nuclear Power Station (NMP2) located in upstate New York
- Certain other intangible assets resulting from the LIPA/LILCO Merger. These assets, together with all other assets of the Authority and LIPA used in the furnishing of electric service, are referred to as the "System." LIPA also accepted responsibility for over $6 billion in debt associated with the electric assets transferred to LIPA.
- As part of the LIPA/LILCO Merger, the remainder of LILCO's electric service assets (including all of its then-existing fossil-fueled generating units), and its entire gas supply system, were transferred to certain wholly-owned subsidiaries of KeySpan Corporation which did business under the name of KeySpan Energy (KeySpan).[4] In August 2007, KeySpan was acquired by National Grid plc (National Grid), a company organized under the laws of England and Wales.[5] Effective May 1, 2008, the subsidiaries of KeySpan Corporation began doing business under the name National Grid.

Since 1998, the Authority has contracted with KeySpan and then National Grid to provide the majority of the services necessary to serve the Authority's customers.

3.1 Regulations

As a public authority, LIPA is subject to a variety of rules and regulations and oversight by various State and Federal Agencies, including the following:[6]

- LIPA must comply with Internal Revenue Service (IRS) guidelines for qualified management contracts in order to maintain its tax exempt status. These guidelines cover arrangements with third-party management service contracts used by LIPA to execute utility operational functions for which it is responsible.

- Pursuant to the Act, the Authority is required to obtain approval of the Public Authorities Control Board (PACB) before undertaking any "project". The PACB was created in 1976 in response to the growing amount of Public Authority Debt. It is

[4] Biennial Report of the Consulting Engineer and Rate Consultant for the Period January 1, 2010 through December 31, 2011.
[5] On February 26, 2006 National Grid and KeySpan entered into a Merger Agreement.
[6] DR 603, 604 and 605

codified in Section 50 of the NYS Public Authorities Law. The PACB is a five member board appointed by the Governor. A "project" is defined by the Act to mean an action undertaken by the Authority that: 1) causes the Authority to issue bonds, notes or other obligations or shares in any subsidiary corporation; 2) significantly modifies the use of an asset valued at more than $1 million owned by the Authority or involves the sales, lease or other disposition of such an asset; or 3) commits the Authority to a contract or agreement with a total consideration of greater than $1 million and does not involve the day-to-day operation of the Authority.

- Pursuant to the Act, LIPA must obtain the written approval of the NYS Comptroller of any private sale of bonds or notes issued by LIPA and the terms of such sale. By letter dated July 22, 1999, the Comptroller set forth his determination that pursuant to Section 1020-cc of the Act, certain LIPA contracts that exceed what is now a $50,000 threshold must be approved by the Comptroller before such contracts become effective. The Authority submits LIPA contracts, as well as certain qualified third-party National Grid contracts, to the Comptroller for approval. In addition, the Comptroller periodically conducts audits of LIPA to examine LIPA's policies, procedures, controls and other financial and management practices. As part of the Comptroller's review and approval process, the NYS Attorney General reviews and approves the contracts submitted to the Comptroller "as to form."

- In December 2009, the NYS Public Authorities Reform Act (PARA) was signed into law. Among other things, PARA created an independent Authorities Budget Office (ABO) with certain oversight powers and expanded on the filing and publication requirements of the Public Authorities Accountability Act (PAAA). Specifically, the requirements as set forth in the PAAA and PARA include requirements related to: the reporting of certain information publicly and to the ABO, the duties of the Board of Trustees, lobbying, property disposition, appointment of the CEO, mission statements and measurement reporting, subsidiaries of public authorities, public authority debt, and whistleblower protection.

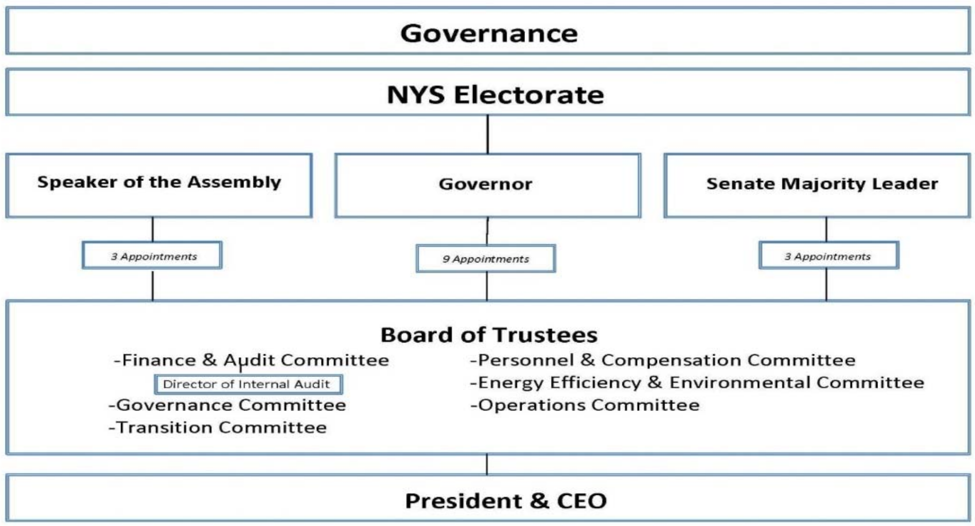
- The Authority's rate proposals, as well as other changes to LIPA's tariff and regulations, are subject to the requirements of the State Administrative Procedures Act (SAPA). SAPA requires: notice published in the *New York State Register*; a proposal memo available on LIPA's website and at its headquarters; a 45-day public comment period; public comment hearings held in both LIPA Counties (Nassau and Suffolk); proposal and comments summarized for the Board of Trustees (BOT); resolution placed on the Board agenda at an open meeting; and BOT discussion and vote on the resolution. Approved rates become effective upon filing with the NY Department of State.

3.2 Operating Structure

LIPA is governed by a fifteen-member BOT – nine appointed by the Governor, three by the Senate Majority Leader and three by the Speaker of the Assembly. As of the audit period, the LIPA BOT is empowered to set rates without the approval of the New York State

Public Service Commission (PSC). **Exhibit 3-2** provides LIPA's current governance structure.

Exhibit 3-2
LIPA Governance Structure – March 2013



Source: LIPA Organization Chart, March 2013 (DR 2)

The majority of LIPA's utility operations functions are performed by National Grid (formerly KeySpan), under the MSA that provides for the day-to-day operation of LIPA's T&D business, including customer service and support functions. The current Amended and Restated MSA was adopted on January 1, 2006 with a term through December 31, 2013. A history of the MSA and its amendments is provided in Section 3.9 below. In addition to the MSA, LIPA has other agreements with National Grid subsidiaries related to various power supply services.[7]

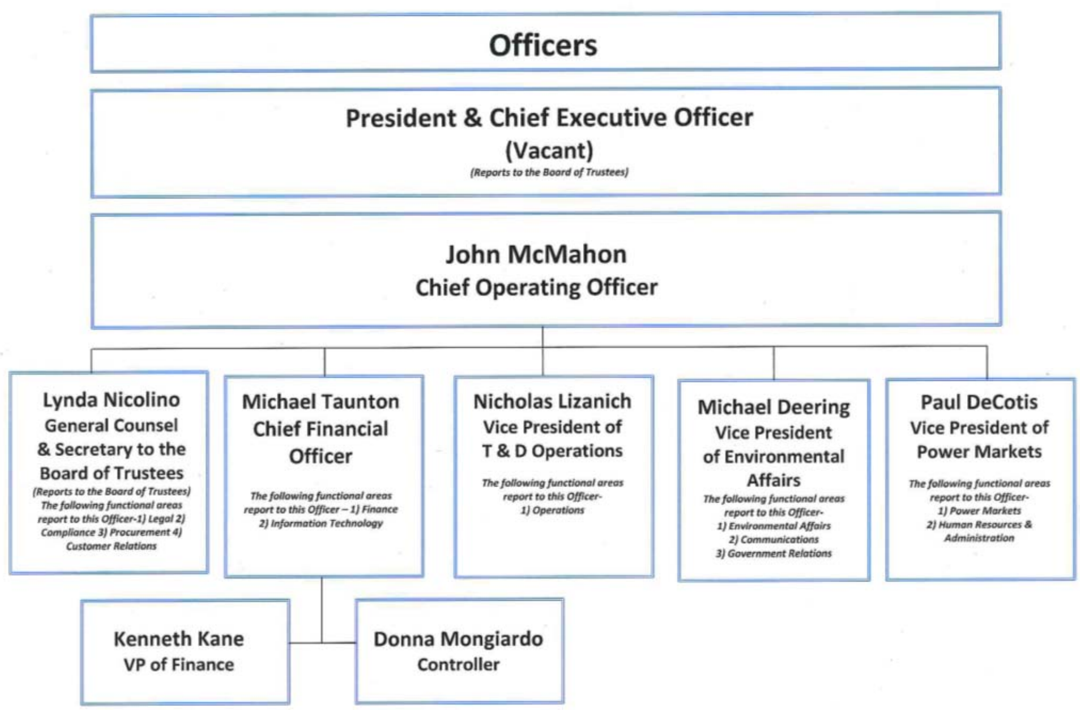
National Grid is paid a service fee for the operation and maintenance of LIPA's system.[8] In 2010, the fee was approximately $286 million.[9] In addition, National Grid is paid for any pass-through expenditures (such as capital costs and storm events) and exogenous cost adjustments for items outside National Grid's control (such as changes in laws and regulations, mutual aid costs, and other services not specified by the MSA). National Grid is also subject to a performance disincentive which was initially capped at $7 million annually and increased to $11 million in December 2009, for failure to achieve targeted performance levels in such areas as customer service and reliability.[10]

[7] Discussed in Chapter 18 - Power Supply and Fuel Management
[8] The fixed fee is paid on a monthly basis
[9] April 9, 2013 Presentation on Management Audit Topics
[10] Discussed in Chapter 6 – Contract Management and Performance Measurement

LIPA directly employs approximately 95 individuals in executive and management roles with responsibilities for general management and corporate-level financial functions, contract oversight and coordination, and the performance of certain other functions for which LIPA retained responsibility. National Grid employs approximately 2,000 employees dedicated to the day-to-day operation of the system.[11] A number of National Grid employees provide support and back office services to LIPA on a shared basis with all National Grid companies. Most of these shared back office personnel are physically located off Long Island, predominantly in Syracuse, New York.

Exhibit 3-3 illustrates LIPA's current executive management structure.

Exhibit 3-3
LIPA Organization – May 20, 2013



Source: http://www.lipower.org/pdfs/company/trans/LIPAorgchart.pdf.
Note: John McMahon became the Chief Operating Officer (COO) in April 2013. Previously Michael Taunton served as CFO and Interim COO.

3.3 Rates and Public Perception

LIPA's rates are among the highest in New York State, as shown in **Exhibit 3-4**,[12] and public perception of the Authority is extremely poor. LIPA is subject to extensive public and political scrutiny and media coverage is typically negative.

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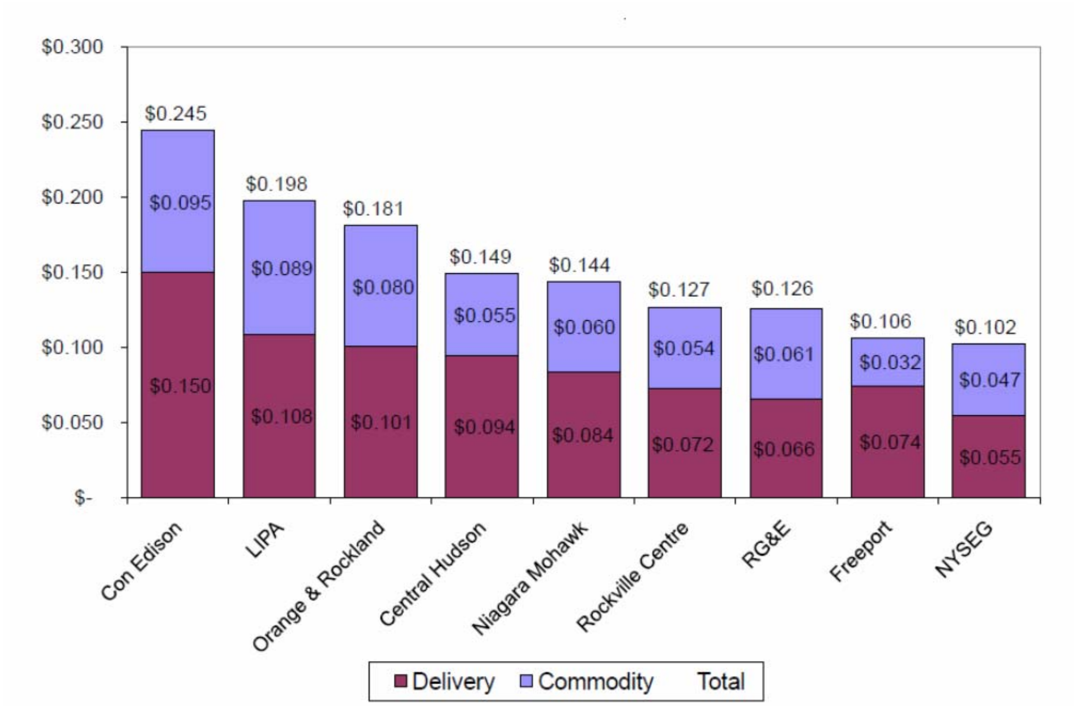
[11] Some personnel in the National Grid organization also provide services to National Grid's gas operations on Long Island.
[12] DR 388

Exhibit 3-4
New York State Residential Electric Rates, December 2012



LIPA's 2013 operating budget totals $3.597 billion, and includes the following components: [13]

- **Fuel & Power Costs**, which include generation and transmission capacity, make up approximately 42.6 percent of the 2013 revenue requirement and reflect the costs of LIPA's procurement of fuel and energy.
- **T&D Operations and Maintenance Expenses,** approximately 19.1 percent of total costs, reflects non-energy expenses, primarily those incurred under the MSA.
- **Interest Depreciation and Financial Reserve,** which makes up 1.5 percent of the 2013 revenue requirement.
- **State and Local Taxes and Assessments,** comprising 16.2 percent of total costs, including property and revenue taxes and payments in lieu of taxes (PILOTS).[14]
- **Other Costs,** LIPA's energy efficiency and renewable programs account for 3.3 percent of the revenue requirement, LIPA's salaries and benefits contribute 0.6 percent, and administrative and professional services costs are 0.7 percent.

LIPA generally ranks in the fourth quartile in JD Power customer satisfaction surveys and has ranked similarly poorly in other customer satisfaction surveys which cross industries. Following Hurricane Irene and Hurricane Sandy, public sentiment may well be at an all-time low. LIPA has undergone substantial organization change in recent years, most significantly

[13] Approved 2013 Budget (www.lipower.org)
[14] PILOTS are typically paid by municipal utilities in lieu of taxes paid by Investor-Owned Utilities (IOUs)

following Hurricane Sandy. The LIPA CEO position has been vacant since September 2010. The BOT is currently operating with eleven trustees.

3.4 Revised LIPA Operating Model

In 2010, LIPA retained an independent consulting firm, The Brattle Group (Brattle), to conduct a study that considered three primary strategic alternatives:

1. Transferring the National Grid/LIPA workforce into LIPA's organization (termed municipalization);
2. Continuing to outsource much of LIPA's T&D, customer service and various planning, corporate and administrative functions, but under an different contractual arrangement with a third-party service provider (designated the "ServCo" model); and
3. Selling the assets and business to a private entity, with the buyer becoming the new electric utility for Long Island (termed "privatization").

Brattle's approach was to estimate the cost structure for each of the options and determine the impact that implementation of each would have upon retail electricity rates. The study then sought to rank the options based upon the quantitative analysis as well as qualitative consideration of risk and option values.

In its October 2011 final report, Brattle concluded that privatization would be significantly more costly than the other two alternatives, and therefore, did not recommend that option. Estimated cost differences between the remaining alternatives, municipalization and ServCo, were considered not material and both would continue LIPA's not-for-profit status. However, Brattle recommended adopting the ServCo option:

> "Overall, we recommend adopting the ServCo model because it retains the efficient operations achieved by privatized utilities while taking advantage of tax exempt financing. It also reduces transitional risks, thereby probably expediting improvements in customer service. This approach also reduces the transitional risks (compared to the Municipalization option) associated with organizational transformation and information system development, thereby expediting improvements in customer service and shifting many risks associated with transitional issues away from itself and to the service provider. Finally, it is not a once and for all decision; LIPA can move to a fully municipalized utility if it finds resolution of the open issues are conducive to such."[15]

On October 27, 2011, the LIPA Board of Trustees approved the revised ServCo business model with a goal of converting LIPA's operations to the new business model based on a dedicated business unit providing services exclusively to LIPA beginning in 2014.

The ServCo model has several key differences from the current operating model. Under the current agreement with National Grid, many support systems and some key functions are

[15] Brattle Study, p viii.

shared with National Grid's gas operations on Long Island. As examples, currently the same individuals read both gas and electric meters along a route and the customer information system houses both gas and electric customer information. A number of other necessary support and back office functions are fully integrated with National Grid Shared Services functions throughout the National Grid corporate structure. With the ServCo operating model, all systems and employees needed to service Long Island electric consumers would be dedicated solely to LIPA work. This dedication of systems and personnel has been termed "portability" as it would enable LIPA to relatively easily transfer to a new third-party supplier or move towards either privatization or municipalization at some future time.

3.5 PSEG Long Island LLC

In 2009, LIPA issued a Request for Information (RFI) to evaluate the market for a new service provider and issued a formal Request for Proposal (RFP) on June 3, 2010. On December 15, 2011, LIPA's BOT approved Public Service Enterprise Group, Incorporated (PSEG) and its subcontractor Lockheed Martin (LM) as LIPA's new service provider.

The terms of the agreement were established in the OSA, signed December 28, 2011, for the operations and maintenance of LIPA's system effective January 1, 2014 for a period of ten years. Significant differences from the prior MSA include:

- Change in the fee structure from a flat fee for most services, to a fee for the executive management costs plus a profit, with all other costs as a pass through.
- Services to be provided by a dedicated subsidiary
- Modified performance incentive/disincentive structure.[16]

Consistent with the newly adopted operating model, personnel engaged in the routine delivery of Operations Services will be employed by a separate wholly owned business unit, PSEG Long Island LLC (PSEG-LI) rather than PSEG directly. These personnel were to be dedicated exclusively to conducting LIPA's electric operations and serving LIPA customers.

Under the OSA, PSEG-LI will operate and maintain LIPA assets used in the provision of Operations Services. LIPA will continue to own, lease or otherwise control all assets associated with the provision of electric services. PSEG-LI will employ the general workforce, operate the T&D business and hold some third party agreements as required for providing Operations Services. PSEG-LI will also manage third party contracts for goods and services.[17]

Exhibit 3-5 provides the proposed PSEG-LI structure as of mid-2013. The organization structure was subject to change, and has not yet been approved by LIPA management or any member or committee of the BOT. PSEG planned to establish a Senior Management Team (referred to as "ManageCo") that would have primary responsibility for the daily management of PSEG-LI, and will participate in routine governance activities with LIPA to

[16] April 9, 2013 Presentation on Management Audit Topics

[17] The New York State Legislature enacted legislation in July 2013 as this audit was being completed that will have a dramatic effect on LIPA's organization and the agreement with PSEG. The discussion that follows is based on the original OSA

ensure the services being provided by PSEG-LI personnel are aligned with LIPA's needs and expectations. The ServCo was to be staffed mostly with personnel currently providing the same services, although the details of the transfers was still be developed at the time of this audit (May 2013).

Under the OSA, LIPA is to establish policy and strategy and provide overall direction to PSEG-LI as it relates to LIPA's T&D business. LIPA and PSEG-LI were to form a Joint Operating Committee (JOC) for oversight and coordination of PSEG-LI and the OSA in general. The membership of the JOC was to consist of an equal number of senior representatives from each party.[18]

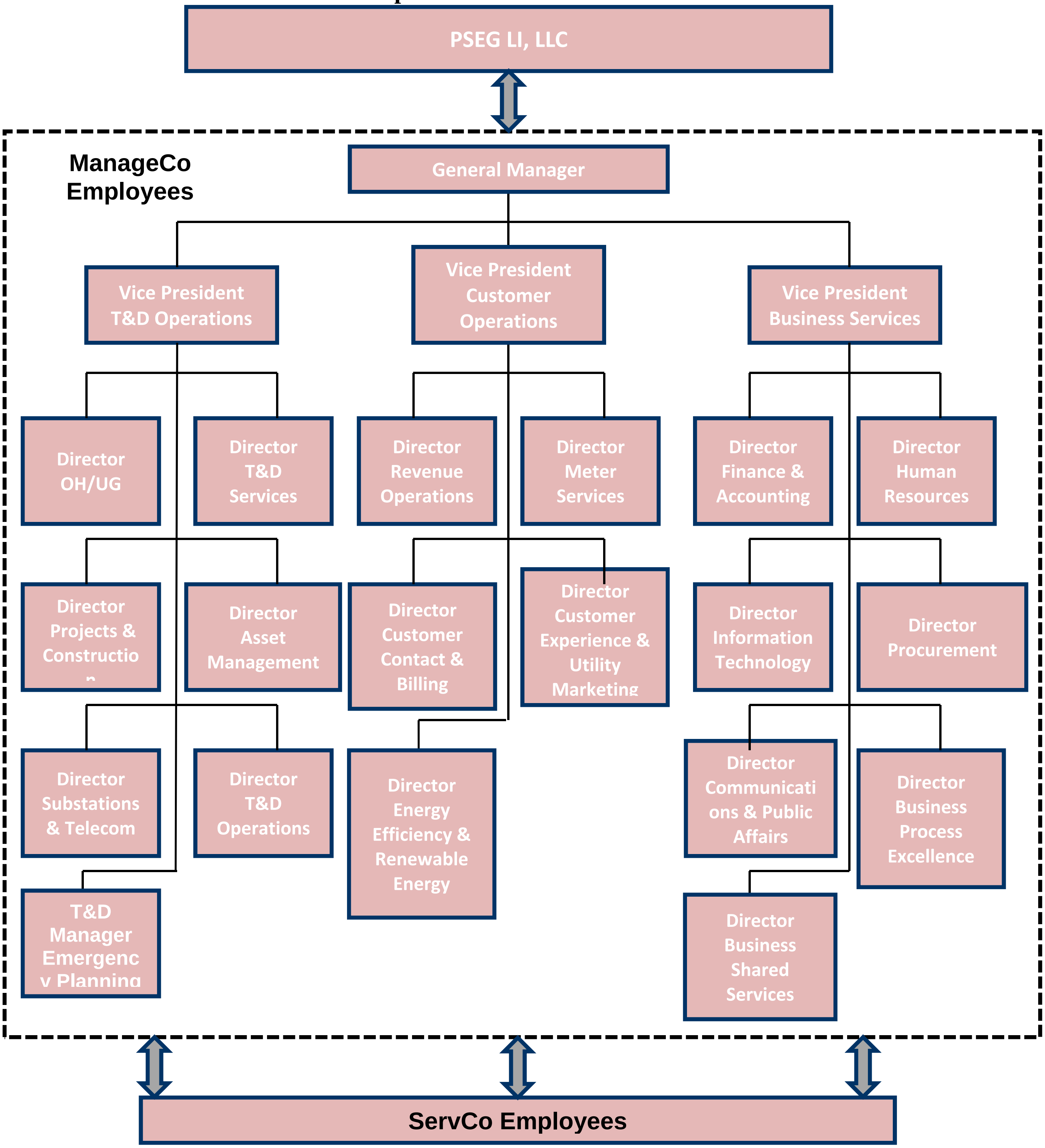
Concurrent with the execution of the OSA, and to facilitate the transition to the new service provider, LIPA entered into a Transition Service Agreement (TSA) with PSEG-LI. Under the TSA, PSEG-LI was to perform the following activities during the period from December 2011 to the OSA effective date of January 1, 2014:

- Organize a wholly-owned service company – ServCo – as a New York limited liability company.
- Prepare detailed annual and five-year operating, capital and energy efficiency budgets and work plans for the period commencing January 1, 2014.
- Become familiar with the activities and business processes currently performed by National Grid which would become PSEG-LI's responsibility, including emergency response and disaster recovery.
- Develop a contract administration manual.
- Secure and integrate the use of systems and facilities.
- Identify any functional gaps in assets, information technology (IT) systems, processes or other elements.
- Develop staffing, employee pension and benefit, labor relations, and training plans
- Develop communications plans.
- Coordinate with National Grid
- Recommend performance metrics for the first year of the contract.[19]

The TSA included a Front-End Transition Plan and Schedule prepared by PSEG-LI and LM, and established a Transition Committee consisting of five representatives from LIPA and four from PSEG-LI to oversee the transition. In accordance with the Transition Plan, PSEG-LI conducted a due diligence review of existing functions, processes and procedures which resulted in the development of over 350 improvement recommendations in nine functional areas.[20]

[18] The OSA did not specify the number of members,
[19] Transition Services Agreement
[20] DR 254

Exhibit 3-5
Proposed PSEG-LI Structure



Source: DR 29

3.6 Hurricanes Irene and Sandy and the Nor'easter

Beginning late evening August 27, 2011, LIPA's service area began to experience the devastating effects of Hurricane Irene (Irene). Irene was a tremendous storm, similar in size to Hurricane Katrina. As it moved up the east coast, hurricane force winds extended outward up to 90 miles from the center (180 miles wide), with tropical storm force winds extending outward up to 290 miles (approximately 600 miles wide). Just prior to making landfall in the New York metro area, winds dipped slightly below hurricane force, and beginning late Saturday evening, August 27 and continuing into Sunday August 28, Long Island felt the effects of Tropical Storm Irene with strong tropical force winds and heavy rain. Sustained winds in the 40 – 50 mph range, with measured gusts in excess of 90 mph were experienced and heavy downpours amounted to more than six inches of rain causing flood conditions across Long Island. Saturated ground conditions accompanied by these high winds caused a significant number of downed trees, in turn causing failure of utility poles and power lines. In total, nearly 19,000 damage locations were associated with the 523,000 outages experienced. In just over a week power was restored to all customers affected by Irene. The last event to have a similar impact was Hurricane Gloria that occurred in September 1985, with a similar number of damage locations (18,730), leaving 750,000 customer outages, nearly 50 percent more than Irene.[21]

Beginning late Sunday evening October 28, 2012, LIPA's service area began to feel the effects of Hurricane Sandy (Sandy). Sandy made landfall as a post-tropical cyclone near Brigantine, New Jersey, with 80 mph maximum sustained winds. Because of its tremendous size, Sandy drove a catastrophic storm surge into the New Jersey and New York coastlines. Sandy and the nor'easter that followed nine days later resulted in more power outages to homes and businesses than any other storm in history. This storm was historic, unprecedented and exceeded predictions of experts from such organizations as National Oceanic and Atmospheric Administration (NOAA), the Federal Emergency Management Agency (FEMA) and the US Coast Guard. Across the east coast of the United States, more than 8.6 million electrical customer outages were experienced. On Long Island alone, almost 1.2 million customer outages were recorded, more than twice the number experienced in Irene and, by far, the largest storm to ever hit Long Island. With this storm came strong winds, rain and then snow that toppled countless massive mature trees, downed poles and power lines, and damaged substantial numbers of homes, businesses and LIPA electrical facilities, adding to the already practical difficulties of the restoration effort. Additionally, Hurricane Sandy brought unprecedented flooding to the south shore of Long Island and the Rockaways, taking a number of lives and in its course, destroying many homes and businesses, and making many others unsafe to re-energize without proper inspection and repair.

In total, 1,071,000 LIPA customers were affected by the initial weather system, with an additional 123,000 customer outages resulting from the nor'easter on November 7, 2012. By Wednesday, November 7, just over a week after the storm hit Long Island, 85 percent of all customer outages were restored and LIPA reported it was on target to restore 90 percent of

[21] November 18, 2011 Long Island Power Authority Tropical Storm Irene Storm Report August 28-September 5, 2011, submitted to the New York Public Service Commission (DR 124)

all customers by that evening, until the ensuing nor'easter brought additional damage to the system. This second storm not only brought additional outages, but necessitated that most areas previously surveyed be reassessed for damage. It introduced additional challenges to already difficult working conditions and caused a temporary "stand down" of repair crews due to safety concerns. Over 37,000 damage locations were associated with the 1,194,000 outages experienced as a result of both Sandy and the nor'easter.[22] Media coverage during both events was generally negative and represented another blow to LIPA's already tarnished image.

3.7 Moreland Commission

On November 13, 2012, Governor Cuomo established a Commission under the Moreland Act to, among other things, investigate the New York utilities' response to and preparations for Hurricanes Irene and Sandy. Due to the "urgent need to address the delivery of power to the LIPA service area and the serious shortcomings in the PSC's authority over electric utilities, the Moreland Commission issued an Interim Report on January 7, 2013."[23] The Moreland Commission's Interim Report found that LIPA and its current service provider - National Grid - struggled in the context of both storms to ensure adequate storm preparation, efficient storm response and effective restoration of customer service. The Moreland Commission found that the LIPA-National Grid management structure contributed to these problems. The Moreland Commission also found that in the context of the provision of electric service during normal conditions, LIPA and National Grid have personnel with overlapping responsibilities related to communications with customers and elected officials, determination of basic policies, and overall management and operations of the system. The usage of the "LIPA" brand name with respect to all matters related to the service area, as well as the overlapping responsibilities between LIPA and National Grid, created confusion with respect to which entity is in charge of service, operations and management, and contributed to severely damaged customer relationships, limited accountability and disconnected management, planning and operational processes.

The Moreland Commission issued its final report on utility storm preparation and response on June 22, 2013. The report addresses the practices of all the NY investor owned utilities (IOUs), as well as certain LIPA-specific topics. Among these were contracting issues identified in an investigation initiated by the Office of the New York State Inspector General (IG), issues regarding LIPA's 2011 delivery charge rate increase, its debt repayment practices, and its erroneous overcharge of $231 million in line losses to its customers.[24]

3.8 Recent Legislative Developments

In July 2013, NYS enacted legislation to restructure LIPA (the Legislation). The Legislation establishes a Long Island Office of the DPS to review and make recommendations with respect to the operations and terms and conditions of service of, and rates and budgets established by LIPA and/or its service provider.

[22] Draft Hurricane Sandy Storm Report October 29-November 14, 2012
[23] Final Moreland Commission Report
[24] Final Moreland Commission Report

The Legislation, in significant part and with varying effective dates, authorizes the DPS to:

- Review and make recommendations with respect to rates and charges applicable on or after January 1, 2016.
- Annually review capital expenditures, emergency response plans.
- Accept, investigate and mediate consumer complaints.
- Review the net metering program.
- Review and make recommendations with respect to the implementation of any energy efficiency measures, distributed generation or advanced grid technology programs.
- Review information related to the OSA metric performance and make recommendations with respect to the Service Provider's incentive-based compensation.
- Restates the requirement for the Department to undertake a comprehensive and regular management and operations audit of LIPA beginning in 2012, and every five years after the second audit, which it requires to be conducted not later than December 15, 2016.

The Legislation, in significant part, also:

- Reduces the BOT from 15 to nine trustees - two appointed by the Governor, one appointed by the temporary president of the Senate, and two appointed by the Speaker of the Assembly. All trustees are required to have relevant utility, corporate board or financial experience.
- By January 1, 2014, requires the BOT Governance Committee to amend its guidelines to keep the staffing of the authority at minimal levels, consistent with ensuring that the authority is able to meet obligations with respect to bonds and notes, and all applicable statutes and contracts, and oversee the activities of the service provider.
- Fix rates and charges at the lowest level consistent with sound fiscal and operating practices and which provide for safe and adequate service.
- Requires the authority and service provider to submit to the Department a three-year rate proposal to take effect January 1, 2016, and thereafter submit any proposals that would increase the rates and charges by 2 ½ percent or greater.
- Requires LIPA and the service provider to prepare an emergency response plan that meets the same requirements imposed on IOUs under Public Service Law (PSL) § 66(21), conduct drills at least once per year, and file a review report evaluating performance during any major storm event if service is not restored within three days.
- Allows LIPA to amend the operating agreement with PSEG-LI.
- Provides a legislative foundation for the issuance of securitized restructuring bonds to refinance outstanding debt of the authority, including the creation of restructuring property by the authority to provide for the redemption or defeasance of a portion of the outstanding debt. The issuance of securitized restructuring bonds is expected to result in lower aggregate T&D and transition charges compared to other alternatives.

Although the Legislation did not specifically establish the size or structure of LIPA's staff, press releases characterized the Legislation as increasing PSEG-LI's responsibilities, requiring a freeze of the delivery portion of LIPA's rates and changing LIPA to a "holding company" structure with fewer employees.[25]

3.9 History of Operating Agreement Changes

1997 Management Services Agreement

In connection with the 1998 merger, LIPA and LILCO/KeySpan entered into an MSA for the operations and maintenance (O&M) of the T&D system and for performance of related construction work for an eight year term. Under the terms of the agreement, LIPA retained control of the T&D assets while the vast majority of the functions typically involved in utility operations were to be performed by the Manager, KeySpan.

- KeySpan was responsible for: day-to-day operation of the T&D system including performance of routine facility additions and improvements, construction activities (O&M and capital work), engineering and related design and construction management services and supervision, preparation of recommended capital and operating budgets, load and energy forecasts and system plans, accounting and tax reporting, procurement, day-to-day legal and tax management responsibilities related to the operation and maintenance of the T&D system, construction work and public works improvements, administration and management of the Authority's interest in NMP2; implementation of emergency response and reporting; customer service programs including response to customer inquiries, marketing, meter reading, billing, payment collection and collection of performance data; preparation of recommended revenue requirements and rate design.
- LIPA retained the rights to determine rates and charges, policies and procedures, review and approve capital and operating budgets, direct the Managers actions with respect to various utility organizations, determine customer service programs, customer and communications policy including bill format, bill inserts and other advertisements, review of the resource plan/model, retained the right to direct the development of the electric power supply resource plan and procure new power supply resources, and review all contracts including power supply agreements. LIPA retained responsibility for management of its financial resources, compliance with Bond Resolution provisions, governmental relations and reporting and overall legal responsibilities.[26]

Under the agreement, LILCO/KeySpan was paid a service fee consisting of a fixed direct fee (90 percent of the direct cost budget), third party costs, a variable payment (lesser of budgeted or actual direct and third-party costs minus the direct fee and third party costs), a management fee ($15 million cap - $5 million of which must result from cost savings), an additional cost incentive fee (50 percent of costs less than budget capped at 15 percent over total budget), and non-cost performance incentives/disincentives. The performance incentives/disincentives were tied to achievement of reliability indices, worker safety, call

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[25] NorthStar has not assessed the impact of the Legislation.

[26] June 26, 1997 Management Services Agreement between Long Island Power Authority and Long Island Lighting Company.

answering, meter reading and accounts receivable performance, and sharing of PILOT payment refunds, and were capped at $7.5 million. The Manager absorbs cost overruns up to $15 million. LILCO/KeySpan prepared and recommended the annual O&M budget, annual recommended revenue requirement budget, and five year T&D planning budget. The initial budget was based on the proposed 1997 rate year budget approved in the LILCO 1996 rate case filing adjusted to 1999.

The contract included the following events of default on the part of LILCO/KeySpan:

- **Events of default not requiring cure opportunity for termination:** change of control, failure to achieve the minimum worker safety standard in two out of three consecutive years[27], bankruptcy, and failure to meet credit requirements.
- **Events of default requiring cure opportunity for termination:** failure to achieve the minimum reliability standard for both System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) for any of the same geographic regions, failure to pay or credit undisputed amounts to the Authority, or failure to otherwise comply with the agreement or guaranty.

The MSA was amended on March 29, 2002.

2006 Agreements

On January 1, 2006, KeySpan, KeySpan Generation LLC (GENCO), KeySpan Electric Services LLC, KeySpan Energy Trading Services LLC (collectively the "KeySpan Parties") and LIPA entered into a Settlement Agreement and Release related to the performance of the parties resolving certain matters of dispute (e.g., administrative and general (A&G) allocations, taxes, claims related to overstatement of unbilled revenue, mutual aid costs).[28]

On January 1, 2006, LIPA (the Buyer) and KeySpan (the Seller) also entered into an Option and Purchase Sale Agreement for the purchase and sale of the Far Rockaway and EF Barrett power plants and an Amended and Restated MSA to extend the existing MSA termination date to December 31, 2013. Among other changes, the Amended and Restated MSA:

- Replaced the original cost-plus structure with a "fee for service" structure.
- Allowed for greater LIPA rights of access, including the right to designate up to four LIPA employees at the Manager's offices.
- Expanded the discussion of KeySpan's responsibilities.
- Modified the compensation structure such that the total manager compensation was equal to the lesser of the minimum compensation ($240 million for the first three years) plus the variable compensation (total kWh of LIPA's billed sales less base kWh times the variable price per kWh) and the minimum compensation divided by 80 percent.
- Modified the events of default not requiring cure to include failure to meet customer satisfaction performance metrics for three consecutive years, System Average

[27] For reasons other than major storms or extreme weather.
[28] January 1, 2006 Settlement Agreement and Release (DR 4)

Interruption Duration Index (SAIDI) for two out of three consecutive years (excluding force majeure). Worker safety and the prior customer service requirements were eliminated.
- Added a requirement for the performance of a best practices review.
- Substantially revised the performance metrics designated as either an offset metric or a non-offset metric. Annual penalties net of offsets were not to exceed $7 million or an amount which would result in the Manager receiving less than the minimum compensation. Metric standards were set based on performance through September 30, 2005.

National Grid Acquisition

In August 2007, KeySpan was acquired by National Grid[29] and effective May 1, 2008, the subsidiaries of KeySpan Corporation began doing business under the name National Grid. Concurrent with that merger, LIPA, National Grid and certain of their respective affiliates entered into an Agreement and Waiver, a First Amendment to Option to Purchase and Sale Agreement, a Second Option and Purchase and Sale Agreement, and other related agreements dated March 22, 2007.

Amended and Restated MSA Amendments

- The Amended and Restated MSA was modified/amended a number of times between 2006 and 2012.
- March 22, 2007 Amendment (First Amendment) modified the requirements related to regulatory representation of LIPA, the staffing of on-island storm support and customer service presence, energy efficiency services and participation on the IT steering committee. It also added a Clean Energy Initiative (CEI) performance metric and approved $1 million incremental funding for storm hardening.
- June 5, 2007 Letter Amendment adding manufactured gas plant (MGP) reporting requirements.
- June 29, 2007 Letter Amendment added an additional event of default related to a civil investigative demand from the United States Department of Justice (DOJ) requesting information related to the DOJ's investigation into the New York City (NYC) capacity market.
- May 15, 2009 Letter Agreement for the administration of the Senior Low Income Assistance Program.
- December 22, 2009 (Second Amendment) added additional manager responsibilities, addressed the transfer of critical information system assets, and added to/modified the performance metrics. The customer satisfaction performance metric penalty was increased by $1 million and JD Power Survey results were added to the metric calculation and the maximum penalty was increased from $7 million to $11 million. National Grid was also required to develop an accountability plan for improving customer satisfaction metric performance.
- January 21, 2011 Letter Agreement to provide additional supplemental staffing and resources to support Efficiency Long Island (ELI).

[29] On February 26, 2006 National Grid and KeySpan entered into a Merger Agreement.

4. LIPA ORGANIZATION AND EXECUTIVE MANAGEMENT

This chapter provides NorthStar's review and assessment of LIPA's current organization, executive management, and overall corporate performance measurement. The transition to the OSA and ServCo business model is discussed **Chapter 8 – Transition and Management of the OSA/ServCo Organization**.

4.1 Background

As discussed in **Chapter 3 – Background on LIPA**, LIPA is not a "typical" utility in a number of critical areas. Nearly all core utility services such as system maintenance, procurement, billing and other customer service, and daily system dispatch and operations are provided to LIPA's customers by National Grid under the MSA. A large percentage of LIPA's electric capacity is provided by units owned by a National Grid generating affiliate (GENCO). The procurement of the fuel for the GENCO units and other generation located on Long Island has been provided by another National Grid affiliate, National Grid Energy Trading (NGET). Personnel employed by National Grid provide analytical support to LIPA's power supply planning and procurement activities.

LIPA has four employees officially designated as its representatives within the National Grid Long Island operations. Currently those representatives are the Vice President for T&D Operations, the Assistant Vice President for Planning & Analysis, the Director for Marketing & Sales, and the Director for T&D Planning.

Under the current MSA, LIPA has limited contractual options available to oversee activities and manage National Grid's performance, as discussed in detail in **Chapter 6 – Contract Management and Performance Measurement**. Over and above contractual tools, it is critical that LIPA's leadership team have outstanding management skills and a thorough understanding of utility operations – capabilities that holistically have been called "utility management IQ." For example, the fundamental ultimate responsibility of LIPA for the provision of electric service within its service territory, and therefore the planning and decision making authority to make this happen, must be clear to LIPA staff, all its outside contractors, its customers and other stakeholders. The assignment of roles and responsibilities between LIPA and National Grid should be specific so that duplication of effort is minimized, overlapping and related activities are clearly understood, and that there are no gaps in the responsibility structure or in services performed. Both regular operations and larger projects would be directed and implemented in a coordinated manner, with decisions being made at appropriate levels with all the necessary information. Information regarding key aspects of the operations, performance against goals, pending and rising issues would be provided on a regular basis and in a manner that would allow management to quickly identify trends and monitor progress on projects. There would be a clear connection between corporate goals and performance evaluation.

4.2 Evaluative Criteria

- Are the governance, organizational structure, missions and relationship within LIPA appropriate? Is LIPA's corporate structure sufficiently robust to adequately oversee the provision of electric services?
- Are the spans of control, lines of responsibility, number of management levels, and staffing levels consistent with good utility operations practices?
- Are LIPA's major functions suitably grouped within the organization to provide quality service to customers and sufficient support to operations?
- Where LIPA has delegated authority and responsibility to third parties, are those appropriate in light of best management practices?
- Was LIPA's recent reorganization well planned, and are there adequate plans to monitor organizational performance subsequent to implementation?
- Does the LIPA/outside services provider organizational structure ensure that there is efficient utilization of resources, with no duplication of services?
- Have the impacts of key vacancies and turnover in the Executive Management Team on the operations of the company been properly mitigated?
- Does LIPA have and comply with appropriate procedures and practices related to the scope of this audit, e.g., internal controls, internal audit function and any voluntary compliance with the Sarbanes Oxley Act (SOX)?
- Is an effective process in place to communicate the results of consultant studies, internal audits and other evaluations to Executive Management and to ensure that follow-up action is taken on any noted deficiencies?
- Does the use of internal committees and working groups, both formal and informal, support the formal organizational structure?
- Are the formal and informal paths of communication among the Executive Team and the core LIPA staff reasonable and effective? Are the means of communication between LIPA and its outside service providers and key contractors reasonable and effective?
- Does LIPA use measurable goals, metrics, and key performance indicators to monitor progress towards achieving the corporate mission and objectives? Does LIPA's performance feed back to its corporate mission, objectives and goals?
- Does Executive Management receive sufficient and timely information regarding company operations and performance to enable them to effectively manage the company and its provision of electric service to Long Island?
- Are management performance and compensation programs and performance metrics suitably aligned with the corporate mission, objectives and goals at all organizational levels?

4.3 Findings and Conclusions

4.3.1 LIPA provides governance and oversight to a complex electric utility operation with a relatively small number of resources and vast scope of outsourced services.

- LIPA is presently governed by a Board of Trustees (BOT) appointed by the Governor, Senate Majority Leader, and Speaker of the Assembly.[1] The BOT function and its effectiveness is the focus of **Chapter 5 – Board of Trustees**.

- Currently LIPA directly employs approximately 95 employees, largely in executive and management roles with responsibility for oversight and coordination with National Grid and other outside contractors. **Exhibit 4-1** shows the current organizational structure of LIPA.[2]

  - With such a small LIPA workforce, spans of control, lines of responsibility, number of management levels, and staffing levels are somewhat insignificant.
  - LIPA's recent "reorganization" as a result of the Brattle report is currently in process – the "Transition" to the ServCo model. Transition monitoring is performed via frequent progress reports directly to the LIPA BOT Transition Committee. Issues related to the OSA and the Transition are discussed in **Chapter 8 – Transition and Management of the OSA/ServCo Organization**.

- LIPA's major functions are suitably grouped within its present organization. It is important to note that due to the Transition and recent Legislative activities, LIPA organizational and governance issues are evolving.

- LIPA's organizational structure must interface with several National Grid operating units; these interfaces between the two may result in the appearance, but not the reality, of duplication of roles. **Exhibit 4-2** illustrates the functional interfaces between LIPA and National Grid's Long Island dedicated operations, National Grid Shared Services, GENCO, and NGET.[3]

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[1] Currently four seats on the Board of Trustees are vacant.

[2] DR 1 and materials provided by NYPSC DPS staff to all bidders. Note: The VP Customer Service position was not shown on LIPA organization charts provided 3-25-2013.

[3] Interfaces during the audit period. NGET ceased being LIPA's fuel manager as of May 27, 2013 and the activities were transferred to CEE.

Exhibit 4-1
LIPA Organization

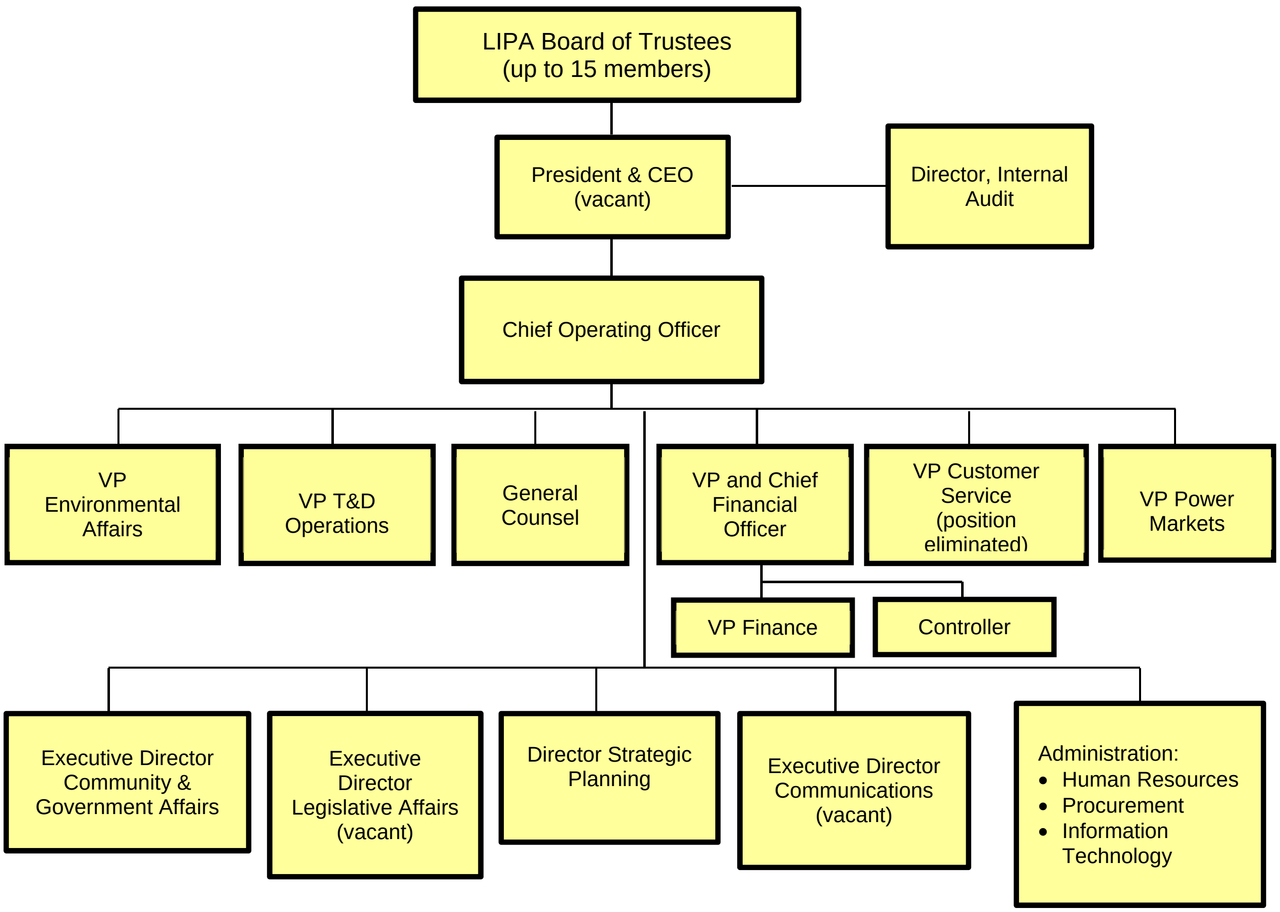
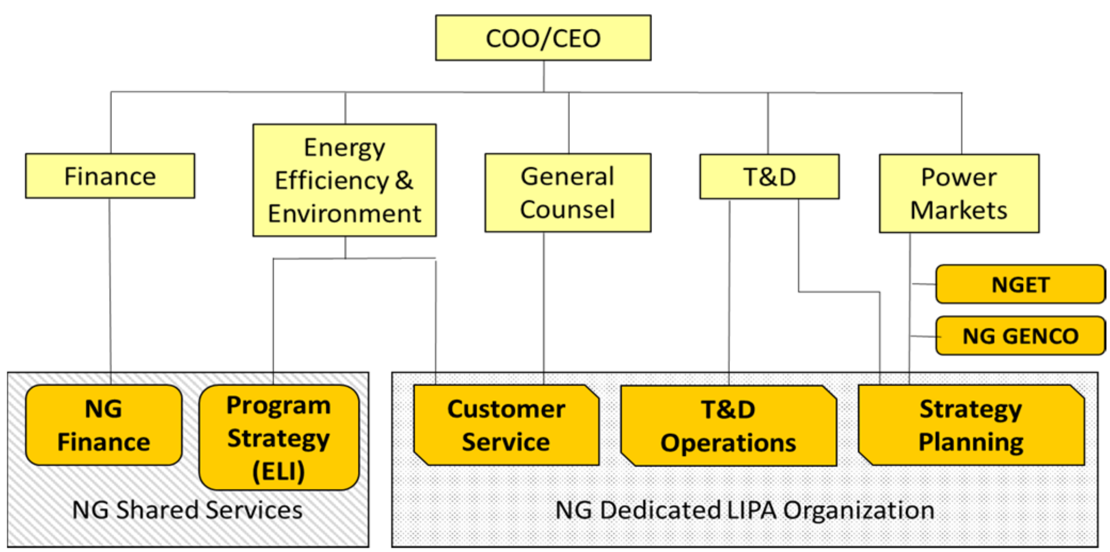


Exhibit 4-2
Interfaces between LIPA and National Grid



4.3.2 Regardless of whether services are performed by LIPA or a contracted service provider, LIPA retains ultimate responsibility for results and effectiveness and therefore must have access to necessary skills and core competencies.

- LIPA owns and for the foreseeable future, will continue to own the utility assets. An important aspect of the utility operation, maintenance and capital improvement program is to protect these assets for the provision of electric utility services to the Long Island customer.

- The MSA specifically recognizes LIPA's ultimate responsibility in a number of areas:[4]

  - MSA 3.1 (F): Right of Access. LIPA shall a right of access to the T&D system and common facilities at all times on an unannounced basis for audit and oversight.
  - MSA 4.16 (D): Books and records upon which the reports and statements required by Article IV shall be made available by the Manager to LIPA for audit by LIPA or LIPA's designated independent auditor.
  - MSA 4.16 (E): In addition to financial audits, LIPA may audit the Manager's and its Affiliates books, records, accounts, facilities, equipment, technology and other materials used in performance of services.
  - MSA 4.18: Capital Asset Control. In each contract year the Manager shall conduct an audit of the capital improvements made in the prior contract year.
  - MSA 4.5 Rights and Responsibilities of LIPA. As the owner of the T&D System, LIPA retains the ultimate authority and control over the assets and operations of the T&D system.

- Because LIPA does not operate like a traditional utility and is not subject to typical utility oversight and regulation, management of the utility has not required a strong understanding of standard utility regulatory requirements.

- Effective oversight of this extensive level of contracted services will always require core competencies. LIPA must do more to ensure that clear expectations are set, execution and performance are assessed, and there is meaningful intervention when requirements are not met.

  - Regardless of how detailed service contracts become and how numerous performance metrics may become, LIPA remains the steward of the ratepayer's trust in the electric utility.
  - In order to ensure that contractors supply the goods and services agreed to under the financial terms and programmatic requirements outlined in their contracts, it is important to conduct proper oversight of contracts. Good oversight holds contractors accountable; poor oversight can result in waste or even fraud or abuse.

[4] DR 4, Contracts; the OSA uses almost identical language, see Chapter 8.

Contract oversight investigations are aimed at continuous improvement and eliminating waste from the amounts spent on goods and services.[5]

4.3.3 LIPA's Executive Team has performed well in a number of areas under extremely difficult circumstances, but not in several key areas.

- The Executive Team is made up of the top seven LIPA management positions: CEO (currently vacant), COO, CFO, General Counsel, and the Vice Presidents of T&D Operations, Environmental Affairs, and Power Markets.[6] The impact of vacancies in key executive positions contributes to the lack of leadership and effectiveness in their respective operational areas, particularly given the small LIPA core resources and required management of a largely contracted utility operation.

- LIPA does not enjoy the benefits of a tenured management team.

  - LIPA has been without a CEO, the top leadership position and principal interface with outside stakeholders since September 2010.[7] Currently, the position is vacant.
  - The previous CEO held the position for only three years (Oct. 2007 to Sept. 2010).
  - The Senior Vice President of T&D Operations was appointed COO in the fall of 2010, but held the position for only two years, resigning in November 2012.
  - The current COO, retained from outside LIPA, has filled the position only since April 2013.
  - LIPA's CFO has held the position for less than two years.
  - The current Vice President of T&D Operations joined LIPA in June 2011, filling a position that had been vacant for nearly a year.[8]
  - For a number of years, LIPA's positions of BOT Chairman and CEO were filled by the same individual, who departed in October 2007.
  - The last BOT Chairman resigned his position at the end of 2012.
  - The Vice President of Customer Service left LIPA in the aftermath of Hurricane Sandy at the end of 2012. Oversight of customer service operations have been distributed among other officers.[9]

- LIPA management has faced three major storms over the past 18 months (Irene, Sandy and the Nor'easter) with considerable public relations and political challenges.

- The Executive Team and LIPA's BOT have identified and acted upon the need for changes in several critical contracts – renegotiation of the PSA, selection of a new Power Manager, selection of a new Fuel Manager, and selection of a new primary service provider (the OSA), along with several major power supply solicitations. The

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[5] Project on Government Oversight: http://pogoarchive.pub30.convio.net
[6] Membership based on regular formal meetings of these specific executive managers. VP Customer Service position not shown on LIPA organization charts provided 3-25-2013.
[7] LIPA News Release August 26, 2010.
[8] LIPA News Release June 29, 2011.
[9] DR 245

Executive Team has negotiated contracts and overseen transitions that required cooperation of the incumbent providers to convert to the new providers.

- The Executive Team has coordinated several crucial financial transactions and has met the requirements for financial reporting.

4.3.4 The Executive Team does not fully appreciate all of LIPA's requirements and there has been little attention to many critical long-term, strategic and essential risk and performance monitoring initiatives.

- LIPA does not have a comprehensive risk register or risk mitigation plan, as discussed in **Chapter 7 – Enterprise Risk Management and Strategic Planning**.

- LIPA does not have a strategic plan for the provision of electric service to Long Island, as discussed in **Chapter 7 – Enterprise Risk Management and Strategic Planning**

- LIPA does not have a long-term strategy to achieve rate reduction, as discussed in **Chapter 11 – Capital and O&M Budgeting**.

- LIPA personnel do not have performance goals other than at a general level (discussed later in this chapter).

- Despite several investigations and plans to improve Customer Service and Communications, minimal executive attention has been applied and no meaningful progress has been achieved, as discussed in **Chapter 14 – Customer Service**.

- In short, the Authority operates in a reactive mode as it relates to many operational matters.

4.3.5 There is no member of the Executive Team with an exclusive focus on Customer Service or on Human Resources (HR) and personnel matters.

- The lack of a VP for Customer Service is troubling given the Authority's poor customer service and low customer satisfaction. As discussed below and in **Chapter 14 – Customer Service**, responsibilities for various aspects of Customer Service have been assigned to three different officers, diffusing attention to one of LIPA's most serious problem areas.

- The lack of a focus on HR is troubling given the daunting transition to PSEG-LI and the uncertainty faced by personnel throughout the organization.

4.3.6 The Executive Team manages its contracts with limited attention to the need for the contractors to provide improved value for the fees paid.

- Currently, if National Grid spends the capital dollars budgeted, LIPA it is viewed by LIPA as meeting the terms of the MSA. With a "spend the money" objective, LIPA's Executive Team is not sufficiently concerned with how the work was done or whether it could have been done more efficiently.[10] If a capital project goes over budget, the overage is simply met by deferring other project work. The Executive Team does not investigate why projects cost more or attempt to apply the experience to future projects. **Chapter 11 – Capital and O&M Budgeting** provides additional discussion of the budgeting function.

- When provided with an opportunity to improve the staffing of the call center, and thereby improve call answer times, LIPA denied National Grid's request for cost reasons, not accepting the value gained by improved responsiveness to customer inquiries. As long as National Grid was meeting the answer rates in the MSA, no improvement was needed. **Chapter 14 – Customer Service** provides additional discussion of the customer service function.

- The view of the Executive Team regarding the scope of its responsibilities is limited to management of the MSA and other contracts. LIPA does not presently recognize any higher obligation to identify issues or risks related to the operation of the system, or to plan for the overall future of electric customers on Long Island. Nor does LIPA determine whether National Grid conducts risk analyses or any type of longer-term planning. Such analysis is not required under the MSA and therefore LIPA does not request this from National Grid. **Chapter 7 – Enterprise Risk Management and Strategic Planning** provides additional discussion of these issues.

4.3.7 The absence of an Internal Audit function within LIPA's organization has virtually eliminated the ability to monitor and verify compliance with internal policies and procedures, as well as compliance by outside contractors with contract terms.

- In general, LIPA has policies and procedures for most of the activities within its organization and under its direct control. However, LIPA has not verified compliance with internal policies, and has exercised few opportunities to review and control the actions of its outside contractors.[11] Without an audit function to ensure compliance and effectiveness, LIPA policies and procedures cannot provide effective, comprehensive and timely controls.

- LIPA hired a Director of Internal Audit in September 2012. However, there is no plan to staff an internal audit function other than with contracts for audit resources currently in process.[12] Communications between the Director of Internal Audit and the Audit and Finance Committee of the BOT has been limited, as discussed in **Chapter 5 – Board of Trustees**.

- LIPA is not subject to the SOX requirements and has taken only minimal activities related to voluntary compliance with SOX specifications.

[10] IS 27
[11] DR 704 and other DRs involving policies and procedures.
[12] DR 755

- LIPA has limited control over the actions and operating decisions of its contracted service provider. The MSA contract provides few leverage points through which LIPA can influence the behavior of National Grid.[13] Coupled with the lack of an audit function, there has been minimal effort to push National Grid toward preferred utility practices or improved performance.
  - No audits (other than annual financial audits) of LIPA's compliance with internal policies and procedures have been conducted in the past five years.
  - Some audits of National Grid's compliance with the MSA have been conducted, and are discussed in **Chapter 6 – Contract Management and Performance Measurement**.
- The new Director of Internal Audit did not prepare a 2013 audit plan until May 2013, based on information he had gathered himself, as LIPA does not have an enterprise risk management program, as discussed in **Chapter 7 – Enterprise Risk Management and Strategic Planning**.

4.3.8 Communication of results of consultant studies and other evaluations is appropriate. Compliance by National Grid does not always occur.

- The Executive Team is highly involved in the monitoring of consultant studies and other evaluations and is well informed regarding conclusions and recommendations. They are able to ensure that recommendations relating to areas of LIPA responsibility are implemented in an appropriate manner.
- Recommendations for changes in National Gird policies or procedures are seldom implemented. Reasons for non-compliance vary, but often include that National Grid's internal control functions believe the existing procedures are adequate.[14]
- National Grid did appropriately pursue implementation of the recommendations of the Baker Tilly review of the Efficiency Long Island (ELI) program audit.[15]

4.3.9 Communications between LIPA and National Grid rely on numerous coordinating committees and informal communication channels, and are generally adequate.

- LIPA has a large number of committees that meet regularly (weekly or monthly) to discuss projects and issues, review analyses, and develop recommendations for next steps. Most of these committees include both LIPA and National Grid personnel and this interaction is an essential part of communicating issues and decisions. Many of

[13] For example, NG declined to make any modifications to Information Systems (IS) security protocols as recommended by LIPA's external auditor (DR 742)
[14] DR 644 and 742.
[15] DR 647

the committees operate with an agenda and maintain minutes or other documentation from the meetings.[16]

- Among LIPA personnel, frequent informal communication occurs between functional groups at both Executive Team and staff levels.

- Major decisions or recommendations to the BOT are made at weekly Executive Team meetings. Presentation of an issue for discussion and decision is typically done by the functional VP without staff in attendance. When decisions require documentation of analyses, written support of analyses and recommendation is generally available.

- Coordination with National Grid occurs both informally and through weekly coordination meetings. The weekly meetings rotate through focused agendas for Operations, Shared Services, Customers and IT on a monthly basis.[17]

- Decisions by Executive Team are usually verbally communicated to LIPA personnel by the functional VP. There is minimal formal communication of decisions from the Executive Team to LIPA personnel.

4.3.10 Members of the Executive Team receive or have access to numerous regular monthly or more frequent reports. Their value in tracking performance and progress in key areas and functions is mixed.

- LIPA and National Grid produce dozens of reports on a daily, weekly, monthly, annual and multi-year basis.[18]

- The principal report used to communicate LIPA performance to the Executive Team and BOT is the Monthly Operating Report, prepared by National Grid. Preparation of this report can take up to two months to complete, e.g., the report on December 2012 operations was issued February 6, 2013; the March 2012 Operating Report was not issued until June 15, 2012. Given the lack of timeliness, the report's effectiveness is limited and questionable.

- LIPA does not prepare its own report on operations, so there is no regular consolidated reporting of LIPA projects or activities.

- Up until January 2013, the Operating Report:[19]

  - Was focused exclusively on MSA metrics
  - Had information presented in identical format, regardless of the metric or its variability throughout the year. For example, the JD Power rankings change only annually, but it is presented on a monthly graph.

[16] DR 28, 213, 226, 236, 303, and 583
[17] DR 341
[18] DR 5
[19] DR 18, 229, 310, 643, and 781

- While there is an "analysis" on each metric, it was principally a restatement of monthly performance relative to target and prior year with minimal discussion on causal factors, trends, or possible risks.
- The status on O&M activities was a table, listing multiple types of O&M activities, planned units and actual units year-to-date (YTD), with no discussion of the data.
- Had no presentation on capital projects or capital expenditures, only a chart showing monthly capital cost per customer.
- Had little or no information on power procurement, risk management (hedging), Independent System Operator (ISO) issues/trends, special initiatives, or personnel/HR matters.

- In the January 2013 Operating Report, which provided information on November 2012 operations, several changes were made to the report that improved its usefulness as an operations monitoring tool.[20]

  - The materials were rearranged to place higher level data (revenues, sales, new customers) at the front of the package.
  - Added numerous pages relating to power and fuel supply, generator operations, and transmission line performance.
  - Added information on significant system events and a summary of storm data, environmental events and projects (e.g., releases, remediation projects), legal matters, and smart grid activities.
  - The analysis continues to be comparative rather than causal and identical monthly graphical presentations continue for metrics with little or no movement month-to-month.
  - Despite multiple pages presenting almost identical data, few charts were eliminated from the earlier packet, so the size of the report has increased significantly (30-35 pages to 90 pages) making it unwieldy.

- The reports and information provided to the Executive Team and the BOT regarding major decisions (e.g., the recent Generation & Transmission RFP) is adequate for them to make informed decisions.[21]

4.3.11 There is no direct linkage between performance management, performance evaluations and compensation at any level within the LIPA organization.

- There are no formal processes for evaluating the four Board-appointed LIPA executive management positions (President and CEO, COO, CFO and General Counsel).[22] Although the Personnel and Compensation Committee is chartered with this responsibility it had been inactive until recently.[23]

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[20] DR 643
[21] DR 817, and 302
[22] IR 8 and DR 11
[23] A new Chair was appointed in 2013, and the Committee Charter was approved by the BOT in May.

- LIPA does not have specific performance goals, targets or weightings for its Executive Management. Executive Management is theoretically covered under the same process as other exempt employees. Nevertheless, performance evaluations for LIPA Executive Management have not been completed.[24]

- The Compensation and Personnel Committee was not involved in the development of Executive Management goals for 2013.[25]

- Employees are evaluated based on a relatively generic skills/competency basis with no specific ties to LIPA's mission, objectives or existing performance measures.

  - All exempt and all non-exempt employees are evaluated using the same, non-job-specific form. [26]
  - Employees are evaluated based on job skills/knowledge, quality and quantity of work performed, availability and timeliness, initiative, teamwork, flexibility, decision-making, leadership, and supervisory skills. The evaluation includes a performance goal component; however, the goals are generally skills/competency based (e.g., additional training or demonstrating more authority).[27]

- Executive management and employee compensation is not currently tied to performance.

- There have been no active incentive programs for any employees, including executive management since 2007/2008 when LIPA's at risk incentive compensation program was eliminated.[28]

- LIPA employees have not had merit salary increases or cost-of-living adjustments since 2009, and promotional opportunities are limited.[29] With the elimination of the short-term incentive, LIPA implemented an across-the-board cost of living adjustment in 2009. In 2010 and 2011 general merit increases were neither planned nor implemented. Salary actions were for promotions, expanded duties, or in limited instances to retain essential skills.[30]

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[24] DR 11, 12. LIPA does not have goals or targets for the President and CEO, COO, CFO, or the VPs of Customer Services, Environmental Affairs, Power Markets, T&D Operations, the General Counsel or the Secretary. A performance evaluation for the Controller was completed for 2009 and 2010.

[25] IR 80

[26] DR 10

[27] DR 10, IR 8

[28] DR 11, DR 8, 9. Prior to 2009, LIPA had an incentive compensation program with between 3 to 30 percent of an employee's compensation at risk. (IR 8)

[29] DR 8, DR 11, IR 8

[30] DR 8

4.4 Recommendations

Recognizing the Transition from the National Grid / MSA operational environment to the PSEG-LI / OSA operational environment, some conclusions arising from the discussion in this chapter are strongly related to the OSA management model and therefore the related recommendations are contained in **Chapter 8 – Transition and Management of the ServCo/OSA Organization**. The recommendations presented here are related strictly to Executive Management, regardless of the service provider or governing agreement.

4.4.1 Actively recruit and retain personnel with a strong understanding of all aspects of utility operations, including T&D field activities, customer service functions, capital project management, and rates and regulatory activities. As the entity ultimately responsible for the delivery of electric power to Long Island, it is essential that the knowledge base and competencies within the organization reflect to totality of the organizations responsibilities to its ratepayers.

4.4.2 Develop a Monthly Operating Report (in conjunction with PSEG-LI) to provide the LIPA Executive Team and BOT with the key information from the entire organization's activities needed for oversight and control, with additional supporting information available if needed. The presentation should be in a format that is easily understood and should include a true analysis of the causal factors, trends and risks arising from performance data.

4.4.3 Develop a formal process for evaluating the performance of LIPA Executive management which includes defined goals and performance targets (tied to the mission and objectives), and involves the BOT and Personnel and Compensation Committee in the development of goals for, and the evaluation of, executive management performance.

4.4.4 Develop employee performance goals which tie to the comprehensive performance management system and are reflected in the employee performance evaluation process.

5. BOARD OF TRUSTEES

This chapter discusses LIPA's Board of Trustees (BOT) and its current role in the Management and oversight of the Authority. The structure of the BOT was described in **Chapter 3 - Background on LIPA**, and is not repeated at length here.

5.1 Background

The LIPA BOT maintains authority over the scope, mission, and along with the Chief Executive Officer (CEO) establishes the strategic direction and fiscal oversight of the Authority. The CEO, along with the executive management team, executes the strategic direction through the operational management of LIPA and its contractors. The Board also has oversight authority of the nomination, appointment, and election of individuals to Board committees and similar roles.

LIPA's Board operates under a set of by-laws, and each of the following Trustee Committees has a specific Mission Statement and Charter:[1]

- Governance Committee
- Finance and Audit Committee
- Energy Efficiency and Environmental Committee
- Operations Committee
- Transition Committee
- Personnel and Compensation Committee (charter is a draft)

Typical duties of the BOT include:

- Governing the organization by establishing broad policies and objectives.
- Selecting, appointing, supporting and reviewing the performance of the chief executive.
- Ensuring the availability of adequate financial resources.
- Approving annual budgets.
- Accounting for the organization's performance.
- Setting the salaries and management compensation.

Under the Public Authorities Reform Act of 2009 (PARA) and its charter, LIPA's BOT Governance Committee must report to the Board on at least an annual basis its actions and recommendations and any proposed changes to the governance charter or guidelines. The Committee is also charged with: developing a description of the competencies and personal attributes required of Trustees to assist those authorized to appoint members to the Board in identifying qualified individuals; reviewing the number and structure of committees created by the Board; and reporting to the Board on evaluations of the performance of the Board, its

[1] DR 30

committees and senior management. In its report covering 2012 the Committee reported Board participation and attendance as follows:[2]

- Article II of the LIPA By-laws requires that a Trustee "who shall have failed to attend six consecutive meetings of the Trustees or at least fifty percent of the meetings of the Trustees during a consecutive 12-month period shall thereupon and without further action be deemed to have resigned as a Trustee of the Authority."
- All attendance requirements were satisfied during 2012. Overall, the attendance of the Board was good (86 percent).

Section 2824(2) of the Public Authorities Law, requires directors to participate in State approved Public Authorities Accountability Act Training regarding their legal, fiduciary, financial and ethical responsibilities as board members of an authority within one year of appointment to a board. The Authorities Budget Office (ABO) recommends Board members complete subsequent training within 12 months of the date of their reappointment. Of the Trustees that served on the Board during 2012, all satisfied their training obligations.[3]

Board members participate in continuing training as may be required to remain informed of best practices, regulatory and statutory changes relating to the effective oversight of the management and financial activities of public authorities and to adhere to the highest standards of responsible governance. The stated purpose of this training is to prepare individuals to understand and properly execute their roles as board members and to be well-versed in the principles of corporate governance and the requirements of the law. Training provides the foundation for directors to exercise appropriate oversight and to recognize the responsibility they have to the mission of their organization, its management and staff, and to the public.

During 2012, the full Board approved the following governance documents:[4]

- Modifications to LIPA's Tariff for Electric Service Related to Change in Delivery Charge
- Modifications to LIPA's Tariff for Electric Service Related to Residential Eligibility
- Modifications to LIPA's Tariff for Electric Service Related to Pole Attachments and Residential Water Heating
- Revised Code of Ethics and Conduct of the Long Island Power Authority
- Modifications to LIPA's Tariff for Electric Service Related to On-Bill Financing
- Revised Guidelines Regarding the Use, Awarding, Monitoring and Reporting of Procurement Contracts
- Modifications to LIPA's Tariff for Electric Service Related to Small Generator Interconnection Procedures
- Modifications to LIPA's Tariff for Electric Service Related to Clean Solar Initiative Feed-In Tariff

[2] Draft Minutes of the LIPA BOT Governance Committee May 23, 2013.
[3] The May 23, 2013 Governance Committee Draft Minutes indicate that the most recently appointed and reappointed Trustees still had to complete their training. During Fact Verification, LIPA provided documentation that all training had been completed by June 7, 2013.
[4] Draft Minutes of the LIPA BOT Governance Committee May 23, 2013.

- Modifications to LIPA's Tariff for Electric Service Related to Service Classification - 11 Market Rates
- Modifications to LIPA's Tariff for Electric Service Related to Excelsior Jobs Program
- Modifications to LIPA's Tariff for Electric Service Related to ReCharge NY Program
- Modifications to LIPA's Tariff for Electric Service Related to Remote Net Metering
- Amended and Restated Power Supply Agreement
- Modifications to LIPA's Tariff for Electric Service Related to Monthly Power Supply Charge
- Negotiated Agreement for Electric Service Pursuant to LIPA's Tariff for Electric Service - Service Classification – 13.

5.2 Evaluative Criteria

- Is the structure and operation of the Board and its Committees consistent with good practices?
- Does the Board exercise a suitable level of authority and responsibility?
- Does the Board participate to an appropriate degree in the development and approval of important authority policy decisions?
- Is the role of the Board of Trustees in the development of budgeting guidelines and periodic budget reviews and approvals appropriate?
- Does the Board properly represent and address the interests of customers and ratepayers in its monitoring of the organization and its decisions?
- Is the Board's role in the hiring and evaluation of the performance of the CEO and other executives appropriate?

5.3 Findings and Conclusions

5.3.1 While the formal structure and by-laws of LIPA's Board of Trustees are generally consistent with typical practices for non-profit boards, municipal and investor-owned utilities, the board size is larger than typical and has suffered from persistent vacancies.

- From 2010 to 2013 the LIPA Board has had a membership of between eight and fifteen members.[5] The Board was at its full authorized membership for six months in 2010, and operated with eight members for a few weeks in 2012. Currently the LIPA BOT has 11 sitting members.

- **Exhibit 5-1** summarizes Board size and board member background for a selection of utilities of comparable size or geographic proximity to LIPA. These utilities show board sizes of between five (for the Los Angeles Department of Water and Power (LADWP)) and 12 (for Con Edison).

[5] DR 860

Exhibit 5-1
Comparison of Utility Board Size and Composition

	Board of Directors				# Customers	Service Area
Utility	# Board members	% with Energy/ Utility experience	% with finance/ banking experience	% with Fortune 500 experience		
LIPA	**15 seats, 11 sitting**	**9%**	**27%**	**0%**	**1.1 M**	**Long Island NY**
New York State Independent System Operator (NYISO)	10	80%	20%	20%	n/a	NY
LADWP	5	20%	0%	0%	1.5 M	465 square miles including Los Angeles
Colorado Springs Municipal Utility	5 City Council 7 on Utilities Policy Adv. Cmtee (UPAC)	57% of UPAC members	0%	0%	0.2 M	Colorado Springs Municipal Area
Con Edison	12	25%	17%	33%	3.3 M Electric 1.1 M Gas	NYC
Public Service Electric and Gas	11	18%	18%	27%	2.2 M Electric 1.8 M Gas	NJ
Wisconsin Electric Power	9	22%	44%	0%	2.2 M	WI + MI Upper Peninsula
Nevada Power	10	30%	20%	0%	1.3 M	NV

Source: NorthStar analysis from public information.

- Typical practice for non-profit organizations is for a Board of between nine and twelve members, with larger Boards most frequent for organizations that rely on Board members for fundraising activities.[6]

- Municipal utilities may be governed by their City Council or by a separate Board, with ultimate rate authority remaining with the Council. If the City Council retains governance authority, there is often provision for an advisory group that provides for review, community input and recommendations to the governing body. (refer to LADWP and City of Colorado Springs in Exhibit 5-1.)

5.3.2 The composition of the LIPA Board is weak for an organization of its size, complexity and revenues, especially as to utility or energy industry experience.

- Typical practice for both for-profit and not-for-profit Boards is to develop a breadth and depth of skill sets associated with business in general (e.g., accounting, finance, law, marketing, and operations) and related to the business' industry. The level of experience and position of board members should be roughly commensurate with the size, breadth, and complexity of the organization.[7]

- The LIPA Board has one member with experience in each of accounting, finance, and insurance, and two members with law degrees. There are three members from the real estate and construction industry, relevant experience for a utility with major construction, project management and real estate holdings. One member has experience in the bargaining unit management, relevant experience for an Authority with represented workers. The backgrounds and tenure of the current LIPA Board members are shown in **Exhibit 5-2**.

- The LIPA Board has only recently obtained its first member with any direct utility experience, and has no members with experience running a similarly large organization, either as an executive or as a Board member.

  - Only LADWP has a similar minimal representation of utility/energy industry experience on its Board,[8] all others have considerable industry expertise represented in their board membership. (See Exhibit 5-1).

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[6] NorthStar analysis
[7] NorthStar analysis
[8] One member out of five total

Exhibit 5-2
Board Members, Background and Committee Assignments
(Listed by Seniority on the Board)

Name	Background	Year Appointed/ Term Expires	Committee Assignment
John Fabio	Public Administration	2003/2013	Governance (chair); Transition
Suzette C. Smookler	Health Care, Education	2006/2016	Governance; Energy Eff. & Env.
Lawrence J. Waldman, Chair	Public Accounting, CPA	2008/2015	Transition (chair)
Susan Gordon Ryan	Government, Non-Profit	2008/2011 (hold-over)	Governance; Energy Eff. & Env.; Personnel & Compensation
Laurence S. Belinsky	Real Estate, Finance	2008/2013	Finance & Audit (chair); Governance; Operations; Transition
Neal M. Lewis	Law, Environment and Public Policy	2009/2013	Operations
Gemma de Leon	Union management, Retail	2010/2016	Operations; Personnel & Compensation
Peter K. Tully	Construction, Law	2011/2014	Operations (chair); Finance & Audit; Transition
Jeffrey H. Greenfield	Insurance, Public Planning	2012/2016	Energy Eff. & Env. (chair); Transition
Michael Maturo	Real Estate, Finance	2012/2016	Personnel & Compensation (chair); Finance & Audit; Transition
Matthew Cordaro	Utility, Education	2013/2016	none

Source: http://www.lipower.org/Authority/profile/trustees.html and linked pages, retrieved April 17, 2013, publically available information, Trustee bios and resumes provided by LIPA during fact verification.

5.3.3 Residency requirements and the inability to compensate Board members may impact the ability to attract Board members with industry and large corporate experience.

- Investor-owned utilities compensate their board members with a stipend or retainer, reimbursement of expenses, and often a fee for attending Board or Committee meetings. Municipal and non-profit boards are often unable to compensate their Board members.
  - LADWP does not compensate its Commissioners, other than a minimal payment (less than $100) for attending meetings; the NYISO does pay its Board members an annual retainer, meeting fee and expense reimbursement.
  - The inability of LIPA to provide compensation to its Board members may limit the ability to interest potential Board members with major corporate and utility or energy industry expertise.
- LIPA Trustees must live in the LIPA service territory. However, given the proximity to New York City and the importance of the Authority to the economic development of Long Island, it should be possible to obtain Trustees with greater depth of experience, particularly in the energy and utility industry.

- In 2012, the Governance Committee provided information on the desired skills and experience for new Trustees to the leadership of the Senate and Assembly related to existing and upcoming vacancies on the Board for which they had responsibility.
- The listing of desired experience included: finance, energy industry, specifically from an electric or gas utility, environmental matters, consumer protection or non-public business experience.[9]

5.3.4 While the Committee structure is typical, the activities of some Committees have failed to recognize some key functional responsibilities designated in their Charters. Additionally, some critical oversight functions are not specifically assigned to any Committee.

- **Exhibit 5-3** summarizes the responsibilities of the six Committees. Between the five standing Committee charters, there are provisions for most of the typical Board oversight functions.[10] Some key oversight functions do not appear to have specific Committee assignments, including, for example, long term strategic, operational and financial planning for the Authority[11] and general safety and environmental compliance.[12]

- The Finance and Audit Committee has directed little time to its internal audit responsibilities or consideration of long term financial strategies; instead it has focused primarily on the operating budget and near term financial matters.[13]

- The Personnel & Compensation Committee was relatively inactive from 2010 to late 2012.[14]

    - From 2010 to 2012, no formal review of LIPA Executive Team members was conducted. Executive personnel matters were conducted by the Board *en banc* during this period.[15]
    - In 2012 the Personnel & Compensation Committee met twice related to the Chief Financial Officer position; in 2013 the re-activated Personnel & Compensation Committee was involved in discussions related to the appointment of the new Chief Operating Officer.

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[9] Review of Committee minutes (DR 16) did not identify this communication; copies of the letters were provided in Fact Verification.
[10] DR 30, DR 747, DR 863
[11] The charter for the Operations Committee is limited to review of operational performance and capital projects, both near term activities.
[12] The Charter for the Energy Efficiency and Environmental Committee only specifies “environment” in the context of renewables and greenhouse gas emissions.
[13] Review of Committee minutes (DR 16), DR 215, DR 747 and DR 862; see Chapter 4, Current Organization and Executive Management for a complete discussion of the internal audit function within LIPA
[14] DR 863
[15] Review of Committee minutes (DR 16)

Exhibit 5-3
Summary of LIPA Board Committee Responsibilities

Finance and Audit Committee Responsible for: • Annual Budget • Debt and Debt Management • Investments • Financial Statements and Disclosure Matters • Selection and Oversight of the Independent Auditor • Internal Control • Compliance Oversight
Governance Committee Responsible for: • Oversee the Authorities governance practices including by-laws, rules and procedures for conducting the business of the Board and the Code of Ethics and Conduct • Advise the Board on the number and structure of committees, the characteristics of qualified candidates for Board membership, and Trustee education, including new Trustee orientation • Coordinate performance evaluations for the Board, its committees and senior management. • Evaluate the Authority's policies, including, equal opportunity and affirmative action, procurement of goods and services, and disposition of real and personal property, • Examine ethical and conflict of interest issues .
Operations Committee Review, monitor and make recommendations related to: • LIPA's operational performance related to system interruption indexes, tree trimming, and safety • transmission and distribution system capital projects and expenditures; • customer service issues, including storm communications; • Revenue collection and arrears outstanding; • Planning and implementation of LIPA's Customer Care and other programs; • Economic development and load growth in the service territory
Personnel and Compensation Committee Responsible for: • Personnel policies and programs • Development of an overall staffing plan (including internal staff resources and outside consultants). • Recommend compensation of the CEO, CFO, COO and General Counsel. • Annually establish the performance goals and objectives for the CEO, CFO, COO and General Counsel; review the annual performance evaluation for each against approved goals and objectives. • Recommendations on Executive Compensation, employee compensation and employee benefit plans. • Consult and advise the Board with respect to senior management succession planning.
Energy Efficiency and Environmental Committee Responsible for: • Review, monitor, and critique environmental, efficiency, renewable, and research and development programs, policies, practices, and actions. • Periodically report to the Board of Trustees on the progress of the programs. • Make recommendations to the Board of Trustees on new or revised programs or corrective actions concerning the programs.
Transition Committee Responsible for: • Coordinating the various transition-related activities of the standing committees; . • Monitoring the general progress of transition activities • Recommend to the Board or other Committees actions necessary or advisable to ensure to the maximum extent possible that transition activities are accomplished effectively, in a timely fashion, and without disruption of service or inconvenience to customers

Source: Board Charters

- The re-activated Personnel & Compensation Committee was not involved in setting any performance goals for executives for 2013; according to its Chairman, this Committee will be involved in Executive evaluation and goal setting going forward.[16]

- The Operations Committee has focused almost exclusively on the solicitation and negotiation of new power contracts and the OSA, with attention turning to other aspects of its responsibility only recently.
  - Since March 2011 the Operations Committee has held only three meetings that included any public discussions – one to discuss the Irene After Action Report in June 2012, and, very recently, two open sessions in March and May 2013. All other meetings have taken place entirely in Executive Session.
  - The matters discussed in executive session (the solicitation and negotiation of new power contracts and the OSA) were appropriate to be handled in Executive Session.
  - Under its charter, the Operating Committee has responsibility for a broad range of other regular and on-going operational matters that were not addressed by the Committee during this time.
  - Recent Operating Committee agendas indicate discussion of specific operating matters (e.g., capital budget update, storm hardening) in open sessions.[17]

- The Energy Efficiency and Environment Committee primarily focused on the implementation of the energy efficiency programs and promotion of renewal energy sources; minutes do not indicate any discussion of other environmental matters typical of utility operations.[18]

5.3.5 In general, the LIPA Board of Trustees functions well and its members are actively involved in discussions and decision-making regarding activities brought to its attention. There is less attention to Authority operational performance, potential issues, future needs, and longer term considerations.

- Attendance at meetings of Committees and the Board is good. Materials are provided to the Board members in a timely manner in advance of meetings and Board members are well prepared. Interactions with Executive Management appear appropriate.

- The quality of the information provided to the Board on regular operations and performance is not as useful as it might be to provide appropriate and sufficient information for understanding and monitoring performance. The information included in the Monthly Operating Report has improved recently.[19]

- Information on specific major topics and decisions (e.g., issuance of RFPs) is sufficient and appropriate.

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[16] Review of Committee minutes (DR 16), DR 863 and DR 861
[17] DR 30, DR 16, DR 745, LIPA Website; The BOT established the Operations Committee in December 2010 as part of the review of LIPA's response to Hurricane Earl.
[18] Such as spills from oil tanks, PCB transformer issues, or power plant site remediation.
[19] See **Chapter 4 - Current Organization and Executive Management** for more discussion.

- The Board exercises its authority in budgeting and budget monitoring in compliance with Budget procedures.[20]

- There appears to be minimal discussion by the Board on operational performance and needs, and some issues are not be addressed in as timely a manner as desired by staff.[21]

5.3.6 The LIPA Board of Trustees has taken an active role in several key initiatives and decisions of importance to the Authority and its ratepayers and should be commended for its diligence in pursuit of a new service provider.[22]

- The Board had an active role in the investigation of alternative business models, culminating in the selection of a new service provider, and in the subsequent negotiation of the OSA and oversight of the transition to the new service provider. Board members worked closely with LIPA Executive Management put the agreement with PSEG-LI in place.[23]

- The Board has been active in directing LIPA to pursue public policy initiatives, such as investment in renewable energy sources and energy efficiency initiatives. There appears to be an appropriate degree of understanding that pursuit of these initiatives involves a tradeoff between cost and public policy.

- The members of the Operating Committee took an active and appropriate role in the preparation of, and evaluation of bids received for new generation contracts arising from, the RFP for new generation. This interactions occurred during executive session, due to the nature of the analysis (open contractual discussions), so the assessment of Board involvement is indirect and through interviews.

5.3.7 The LIPA BOT provides minimal representation of customer interests through the composition of the Board and the limited provision for public comment at its meetings.

- All LIPA Board members must live on Long Island and are LIPA ratepayers. Many of them have a long history of community involvement, which provides a measure of customer or ratepayer perspective on the Board.[24]

- All Board meetings allow for public comment, and Board and Committee meetings are open to the public, except for deliberations appropriately handled in Executive Session. Board decisions are compliant with SAPA requirements.[25]

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[20] DR 185 and DR 814

[21] Review of Board minutes and selected Board meeting webcasts; authorization of the RFP for new generation was deferred for almost two years.

[22] Review of Board minutes and public documents, various interviews.

[23] While the OSA is not a perfect document, as discussed in **Chapter 8 – Transition and Management of the ServCo/OSA Organization,** the move to a new service provider was an appropriate decision.

[24] Public information

[25] Public information, DR 603

- As discussed further in **Chapter 15 – External Communications**, there are minimal additional communications with customers regarding BOT activities. For example, there is minimal specific follow-up on comments made in the public input portion of meetings. The LIPA website is not organized in a manner that makes finding BOT information (e.g., agendas, minutes) easy.

5.3.8 While the LIPA Board has taken appropriate actions in its attempts to hire a new Chief Executive Officer and to address key departures in the Executive Management Team, the nature of the jobs, salary limitations and uncertainty in the future of the organization will continue to challenge recruiting and retention of all Executive personnel.

- LIPA has been without a CEO, the top leadership position and principal interface with outside stakeholders since September 2010, and the position remains vacant.

- Senate approval of the CEO is required pursuant to PAL §1020-f (c) and PAL §2852. This means that any candidate for the LIPA CEO position must have had considerable comfort with the political process along with extensive experience in the operations and management of an electric utility. Identifying a candidate with both these qualities who was willing to assume the job for the salary available was difficult.

- The Board has taken steps to recruit qualified candidates for the vacant CEO position, including engaging a professional recruiting firm. The firm has been unable to identify any qualified candidates who are interested in the position for an annual salary of $295,000.[26] The General Manager of LADWP is paid approximately $360,000 annually and CEOs at investor owned utilities earn many times this amount.

- The Board took appropriate and timely action upon the departure of members of the Executive Team to approve new Officers, specifically the CFO in January 2012 and the COO at the end of 2012.[27]

- The Board was instrumental in identifying and hiring a new Chief Operating Officer with strong utility operations and management expertise from outside the Authority. The candidate's unique qualifications made him an outstanding candidate for the position.

- Recruiting and retention for all executive positions at LIPA are particularly challenging in view of salary restrictions and the (currently) high degree of uncertainty. The lack of clear performance goals and annual evaluations further challenges retention of senior staff.[28]

[26] DR 31
[27] DR 16
[28] Various interviews

5.4 Recommendations

5.4.1 Work with appropriate agencies and officials to encourage maintenance of the Board at full strength and to identify candidates for the Board with experience with larger corporations and energy or utility companies.

5.4.2 Improve the BOT Committee coverage of Authority functions currently not covered. For example, specific Committees should have responsibility for long term strategic planning, enterprise risk management, traditional environmental concerns and activities at the former Shoreham site. Through Trustee orientation and training, and with direction from Board Chair, encourage all Committees to regularly review each of the Authority functions included in their charter scope.

5.4.3 Explore options for enhancing communication with the public regarding BOT activities, including mechanisms for providing response to public comments. (See Chapter 15, External Communications for additional discussion).

5.4.4 Develop a proactive strategy to guide the BOT in recruiting, retaining, and developing LIPA Officer-level personnel.

6. CONTRACT MANAGEMENT AND PERFORMANCE MEASUREMENT

This chapter documents NorthStar's review and assessment of LIPA's management of its outside service contracts. The MSA with National Grid is the largest and most significant of LIPA's outside contracts and is the primary focus of the chapter. LIPA does manage other outside service contracts, however, so the chapter includes a general assessment of the Authority's overall contract management practices. LIPA's contracts related to power and fuel supply procurement and management are discussed in detail in **Chapter 18 – Power Supply and Fuel Management** and so are not included here. Comparisons between the MSA and OSA relative to management and performance measurement are also addressed in **Chapter 8 – Transition and Management of the ServCo/OSA Organization.**

6.1 Background

As discussed in **Chapter 3 – Background on LIPA**, LIPA accomplishes its mission by outsourcing the vast majority of work involved in running the electric system through various contracts with National Grid and other outside contractors. Outsourcing major core utility services requires LIPA to have contracts, controls, and reporting mechanisms in place to ensure the provision of quality, reliable service to its customers.

Effective management of any outside service providers begins with execution of a strong contract that clearly specifies the following:

- Services to be provided.
- Roles and responsibilities of both parties.
- Performance requirements and expectations.
- Reporting requirements, along with clear responsibility for costs incurred in execution of the contract.
- Specified and significant consequences for non-performance.

Once a contract is in place, the contract terms are only as effective as the extent to which they are monitored and enforced, so it is critical to establish processes within the contracting agency to oversee performance of the contracts and to take rapid action should there be variance from contract terms. The centrality of the LIPA MSA to the provision of essential services to LIPA customers increases the importance of contract terms, monitoring and enforcement for service providers.

MSA Performance Measures

The 2006 MSA with National Grid includes 18 performance measures (effectively 23 measures as some include multiple measures or additional measures were added), with a maximum annual contract penalty not to exceed $7 million or an amount that would result in the Manager receiving less than the minimum compensation for such Contract Year, as shown in **Exhibit 6-1**.[1] The MSA metrics fall into three categories: non-offset metrics, customer metrics and operational metrics. Non-offset metrics represent those for which unfavorable performance cannot be offset by favorable performance in another metric. However, favorable performance in a non-offset metric can be used to offset poor performance in another applicable metric.

In December 2009, LIPA amended the MSA, making the following modifications to the performance requirements:

- Increased the Customer Satisfaction penalty from $1 million to $2 million, effective Contract Year 2009.
- Increased the penalty cap from $7 million to $11 million, effective Contract Year 2009.
- Modified the Customer Satisfaction non-offset metric to include the results of the JD Power residential and business surveys (in addition to the current contactor survey[2]) effective Contract Year 2010, with the relative JD Power weighting changing each year.

Exhibit 6-1
Amended and Restated MSA Performance Metrics

Type/Metric	Penalty (2006 MSA) ($000)	Penalty (2009 Amend.) ($000)	Unit	Penalty Trigger	2006 Target	Offset Trigger
Non-Offset Metric						
Customer Satisfaction Index (CSI) Contactor Survey [Note 1]	$1,000	$2,000	Percent	75.21	78.92	82.62
JD Power Residential [Note 2]			Relative Perf	16th/17th of 17 (4th Q)	15th of 17 (4th Q)	13th of 17 (3rd Q)
JD Power Business [Note 2]			Relative Perf	22nd/23rd of 23 (4th Q)	12th of 23 (3rd Q)	10th of 23 (2nd Q)
SAIDI [Note 3]	1,000	1,000	Minutes	68.90	55.50	42.10
Customer Metric [Note 4]						
Actual Meter Read Rate	500	500	Percent	94.78	96.13	97.48
Billing Accuracy (composite number)	500	500	Percent	99.50	99.54	99.59
Days Sales Outstanding (DSO)	500	500	Days	35.66	32.29	29.42
Bad Debt Ratio (BDR)	1,000	1,000	Percent	0.63	0.46	0.29
Electronic Billing - E-Bill Enrollment - E-Payment	250	250	 Customers Transactions	 16,477 1,272,600	 20,477 1,414,000	 24,577 1,555,440
Call Answer Rate/ Average Speed of Answer	250	250	Percent Seconds	91.50 213.9	93.50 168.9	95.50 123.9
First Call Resolution	500	500	Percent	65.65	68.80	71.95

[1] Amended and Restated MSA Section 4.4(A)
[2] The contactor survey is a survey conducted following customer contact with LIPA.

Type/Metric	Penalty (2006 MSA) ($000)	Penalty (2009 Amend.) ($000)	Unit	Penalty Trigger	2006 Target	Offset Trigger
Operational Metric [Note 5]						
Work Plan Completion Index	500	500	Planned units	Failure to complete plan	Complete plans	
Capital Cost per Customer	1,000	1,000	Dollars	185.0	176.0	159.0
Multiple Customer Outages	500	500	Number of customers with >3 interruptions	163,447	109,492	55,536
SAIFI (excluding major storms)	250	250	Months between interruptions	12.0	14.5	16.9
CAIDI	250	250	Minutes	75.6	66.3	56.9
Storm CAIDI	500	500	Minutes	221.1	137.6	54.1
Worker Safety	500	500	Chargeable accidents per 200k hrs worked	7.10	5.14	3.18
Planned Substation Maintenance Backlog	500	500	Backlogged jobs	83	34	0
Primary Cable Faults	500	500	Days	14.69	12.24	9.79
Total	**$10,000**	**$11,000**				
Annual Maximum	**$7,000**	**$11,000**				

Note 1: Favorable performance of the customer satisfaction index could be used to offset penalties from any customer metric except DSO and BDR up to $500k.
Note 2: Added in 2009. If LIPA tied with a peer it was deemed to be higher rank (DR 19).
Note 3: Favorable SAIDI performance could be used to offset penalties from any operational metric except worker safety up to $500k.
Note 4: Favorable performance in a customer metric can be used to offset another customer metric, but not an operational metric.
Note 5: Favorable performance in an operational metric can be used to offset another operational metric except SAIDI, CAIDI and worker safety metrics, but not a customer metric
Source: Amended and Restated MSA and Second Amendment, DRs 19, 25, 108 and 836.

National Grid Performance under the MSA

As shown in **Exhibit 6-2**, National Grid failed to achieve satisfactory performance in one of the two key non-offset metrics (customer satisfaction) in four of the last seven years. In 2008, LIPA alleged, and National Grid refuted, that National Grid failed to meet the customer service metric for the third consecutive year,[3] and was in default of the MSA for failing the metric three years in a row. In accordance with the terms of the MSA which allowed LIPA the option of terminating the contract following the third consecutive year of nonperformance, LIPA declared National Grid to be in default. National Grid contested the default and the parties ultimately settled the dispute without National Grid admitting the failure. The settlement resulted in the Settlement Agreement and Second Amendment which (among other matters) increased the annual customer satisfaction penalty and required National Grid to undertake a number of activities to improve customer service. In 2009, National Grid improved its performance in this area; however, only one contactor survey was performed, potentially skewing the results. Performance again began to decline in 2011.

[3] DR 36

For the period 2007-2012, three events were identified as force majeure: the March 2010 Nor'easter, Hurricane Irene in 2011 and Hurricane Sandy in 2012.[4] Hurricane Irene interfered with National Grid's performance in eight metrics: customer satisfaction; actual meter read rate, days sales outstanding, bad debt ratio, first call resolution, work plan completion index, capital cost per customer and primary and Residential Underground Distribution (RUD) cable faults.

Virchow Krause & Company, LLP, and subsequently Baker Tilly Virchow Krause, LLP (Baker Tilly) have performed audits of National Grid's performance metrics.[5] The scope of their audits included a review of the baseline and standards, the inputs and calculations, and an identification of any required improvements in processes and documentation. The 2006 through 2009 audits identified issues with the calculation of certain baselines and performance metric results, which did not affect the achievement of the performance targets.[6] The 2010 and 2011 audits identified a number of errors in the baseline, some of which would have put National Grid into the penalty range had LIPA not agreed to use National Grid's reported triggers.[7] Baker Tilly also identified some issues with National Grid's calculations and reported performance, the effect of which was to shift some "target" performance to the "penalty" range. For 2011 and 2012, National Grid requested force majeure relief for these metrics.[8]

Exhibit 6-2
KeySpan/National Grid Performance 2006-2012

Legend: T=Target, FM= Requiring Force Majeure Relief, P=Penalty, O=Offset, BT = Baker Tilley Virchow Krause & Company, LLP (Baker Tilly)

Type/Metric	2006	2007	2008	2009	2010	2011 FM	2012 FM [1]
Non-Offset Metric							
CSI- Contactor	**P**	**P**	**P [10]**	**O [2]**	**T**	**T-FM P [3]**	**T**
CSI-JD Power Res. CSI-JD Power Business	**N/A N/A**	**N/A N/A**	**N/A N/A**	**N/A N/A**	**O T**	**T T**	**P [9] P [9]**
SAIDI	**T**	**T**	**T**	**T**	**T**	**T**	**T**
Customer Metric							
Actual Meter Read Rate	**T**	**T**	**T**	**T**	**T**	**T - FM P [3]**	**T**
Billing Accuracy	**T**	**O**	**T**	**T**	**T**	**T**	**T**
DSO	**T**	**T**	**T**	**P**	**T**	**T**	**T**
Bad Debt Ratio	**T**	**T**	**T**	**T**	**P [4]**	**T-FM P[3]**	**T**
E-Bill Enrollment E-Payment	**T O**	**O T**	**O O**	**O O**	**T [5] T [5]**	**T [5] T [5]**	**P-FM T**
Call Answer Rate/ Average Speed Answer	**T T**	**T T**	**T T**	**T T**	**T P**	**O T**	**O T**
First Call Resolution	**T**	**O**	**O [10]**	**O**	**O**	**O**	**O**

[4] DR 22
[5] The 2012 audit was not completed as of May 31, 2013.
[6] DR 882
[7] DR 37
[8] DR 37

Type/Metric	2006	2007	2008	2009	2010	2011 FM	2012 FM [1]
Operational Metric							
Work Plan Completion Index [Note 6]	**T**	**T**	**T**	**T**	**T**	**T**	**P – FM**
Capital Cost per Customer [Note 7]	**O**	**T**	**T**	**T**	**T**	**T**	**T**
Multiple Cust. Outages	**T**	**T**	**T**	**T**	**O**	**T**	**O-FM**
SAIFI	**T**	**T**	**T**	**T**	**T**	**T**	**O-FM**
CAIDI	**P**	**T**	**P**	**T**	**T**	**T**	**T-FM**
Storm CAIDI	**T**	**T**	**T**	**T**	**T**	**T**	**T-FM**
Worker Safety	**T**	**T**	**T**	**T**	**O [8]**	**O**	**O**
Planned Substation Maintenance/Backlog	**T**	**T**	**T**	**T**	**T**	**T**	**T**
Primary Cable Faults	**O**	**O**	**O**	**O**	**O**	**O**	**O**
RUD Cable Faults	**N/A**	**O**	**O**	**O**	**O**	**O**	**O**
Penalty	**$1,000,000**	**$1,000,000**	**$1,000,000 [Note 11]**	**$0**	**$500,000**	**$2,100,000 calculated only $500,000 billed [Note 12]**	**[Note 1]**

Note 1: Unaudited results. As of June 21, 2013, the 2012 metrics had not been audited (DR 882).
Note 2: Only one survey was performed this year.
Note 3: Per Baker Tilly Audit this was a Penalty.
Note 4: Baker Tilly found problems with National Grid's calculation. Correction of errors resulted in a Penalty determination.
Note 5: Per Baker Tilly Audit (DR 37). In 2010, actual performance was below target; however, no penalty threshold was agreed to between LIPA and National Grid. In 2011 actual enrolment performance was above target but defaulted to target as no offset was set for enrollments. According to Baker Tilly, E-Payments were below target.
Note 6: The work plan completion index is outside the scope of the Baker Tilly review.
Note 7: Baker Tilly notes that the capital cost per customer is based on National Grid's invoices to LIPA and has not been independently verified.
Note 8: Per Baker Tilly Audit this was a Target.
Note 9: National Grid's report to LIPA indicates JD Power Survey results in the target range. Underlying excel data files indicate penalty.
Note 10: Unaudited. National Grid did not provide the supporting data.
Note 11: Penalty associated with Customer Satisfaction under dispute between LIPA and National Grid. National Grid contended that LIPA's rate increase had a negative effect on customer satisfaction. (DR 882)
Note 12: The 2011 Baker Tilly audit identified $2.1 million in penalties; however, only the bad debt penalty of $500k was charged to National Grid as the other metrics were excluded due to force majeure. The 2010 audit identified $500k in penalties. Both penalties ($1 million total) were recently invoiced to National Grid, and payment had not been received as of June 20, 2013.[9]
Source: NorthStar analysis based on DRs 19, 36, 108, 412, 836 and 882.

[9] DR 762 and 763

6.2 Evaluative Criteria

- Is the oversight and control exercised by LIPA's Executive Management Team over the performance of its outside service providers and key contractors appropriate and effective?
- Does LIPA have in place effective internal controls to prevent abuses by third-party vendors, including the management and control of levels and cost of service, and are these controls utilized?
- Are there processes and controls in place to ensure that outside service providers meet performance targets and provide value to LIPA and its customers in accordance with contractual agreements and specific assignments, and are those controls consistently applied?
- Does LIPA appropriately monitor contractor service levels and take action as necessary to improve performance?
- Does LIPA use benchmarking techniques to identify and develop performance targets?
- Does the MSA include appropriate performance targets and disincentives/penalties and/or incentives for meeting service level requirements and were they set in a reasonable manner?
- Are compensation programs and performance metrics suitably aligned at all organizational levels?
- Does LIPA have effective change management and continuous improvement processes?
- Are there impediments that tend to constrain performance improvements and has LIPA taken appropriate actions to remove impediments to performance improvements?

6.3 Findings and Conclusions

6.3.1 Given its unique operating environment, LIPA's primary performance management tools are its agreements with its service providers. In general, LIPA's oversight and control over its service contracts has been minimal and inadequate.

- LIPA employees are responsible for overseeing supplier performance or managing the contracts, with the level of oversight and supervision varying based on the contract and nature of the work, as discussed in detail in other chapters of this report.

- The Amended and Restated MSA (referred to as MSA throughout this Chapter) includes 18 performance measures and associated targets. Failure to achieve these targets results in a penalty payable by National Grid to LIPA.[10] In the event that National Grid failed to achieve the minimum performance metrics for customer satisfaction for three consecutive years or SAIDI for two out of three consecutive

[10] Amended and Restated MSA

years, LIPA had the right to terminate the contract without allowing the Manager to cure the performance deficiency.[11]

- As allowed under the MSA, LIPA has four employees embedded at National Grid who have daily contact with National Grid employees in the performance of MSA services.[12] These employees are involved in a variety of ad hoc and regularly scheduled meetings.[13] Other LIPA employees also interface with National Grid in the monitoring of National Grid's performance in their respective areas of oversight.[14]

- Working with National Grid, the Customer Services organization developed a series of more detailed operational metrics which are reported and reviewed on a monthly basis. In some instances service level targets exist beyond those included in the MSA.

- National Grid's Construction Delivery organization provides construction management supervision for LIPA's major capital program work. Supervisors oversee the contractor work force on a daily basis and assure compliance with the engineering design documents and specifications.

- For other constructing organizations such as Overhead and Underground (OH/UG) Lines and Substation Maintenance, first level project supervisors are responsible for overseeing contractor resources. These supervisors monitor the performance of these resources on a daily basis.[15]

6.3.2 LIPA does not make extensive use of benchmarking techniques in general, and, as discussed later, benchmarking was not used in the development of the MSA targets.

- According to LIPA, in the past three years it has only been involved in two studies that it considered best practices or benchmark surveys: an Edison Electric Institute Annual Reliability Study and the PSC Tropical Storm Review.[16]

- A 2009 Best Practices Study performed by Accenture (as required by the MSA) included some benchmarking of capital and O&M expenditures levels, asset values, material inventories, safety, reliability, and some demographic data (e.g., sales per customer, customers per distribution mile); however, these did not result in any changes to the performance targets.[17]

[11] Amended and Restated MSA Section 7.2(A)(1)(f) Note, events of default are excused to the extent of a Force Majeure event, strike or work stoppage or other labor dispute.
[12] DR 32 and 52
[13] DR 52
[14] Direct Observation
[15] DR 46
[16] DR 90 responded to on 8/27/2012. We note that there has been another storm response review since the date the DR was answered.
[17] DR 23

6.3.3 LIPA has standard, if dated, business processes and procedures in place regarding outside contracts; however, they lack specificity related to key contracts.

- LIPA's Management Policies and Internal Control Guidelines document (Management Guidelines) includes appropriate specification regarding the processing, approval and payment of vendor invoices.[18]

- Procedures relative to the processing and review of MSA charges do not provide specifics for documentation or review of supporting schedules.

  - While the Management Guidelines specify that LIPA "exercises its right to review the supporting schedules… to ensure the charges are accurate" the language following refers to receiving aging reports from [National Grid] "periodically" and that outstanding information is reconciled "periodically".
  - A file of dispute forms is to be maintained, but the procedures are silent on how items are identified as in dispute or how they are to be reconciled.

- Procedures for monitoring Fuel and Power contracts are similarly general and do not specify what is to be done if LIPA is dissatisfied with monitored results.

- LIPA does not have a typical "table of authorities" providing the seniority of approvals required as dollar levels escalate.

  - The Management Guidelines authorize invoice approvals for dollars less than one-thousand dollars ($1,000.00) by the individual responsible for the charge, and any amount over one-thousand dollars to be approved by that individual and their Department head (not defined as to immediate supervisor or Vice President).[19]
  - Typical business processes will have additional escalation of seniority as dollar values increase – e.g., at $50,000, Manager's approval; at $250,000, Vice President's approval.
  - While LIPA has a relatively thin management structure, a one-thousand dollar single break point could result in a dilution of attention by senior personnel to larger invoices because they are comingled with smaller, more routine invoices.
  - Check authorization levels are appropriate, requiring two signatures for amounts over $25,000.[20]
  - Contract approval guidelines set forth in Executive Directive #2, are appropriate, limiting signatory authority to officers of the Authority, requiring written approval by the General Counsel, and specifying approval by the BOT.[21]

- Both the Management Guidelines and the Executive Directive are somewhat dated documents. The Management Guidelines have a cover date of November 14, 2006,

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[18] DR 704, Section IV. NorthStar did not audit compliance with the procedures.
[19] DR 704, Section IV
[20] DR 856, Cover Sheet
[21] DR 856, Executive Directive #2.

with individual sections having approval signatures in the first quarter of 2007. The Executive Directive is dated December 1, 2009.

6.3.4 LIPA's minimal oversight and control is due in part to the lack of any Internal Audit function within the LIPA organization.

- LIPA only established an internal audit department, consisting of one individual, in September 2012. Prior to this LIPA relied on National Grid (or its predecessor KeySpan) to develop an audit plan and perform risk assessments.[22]

- The MSA includes internal audit as a National Grid functional requirement.[23] Even though few audits have been performed by any party, it is questionable whether audits of National Grid by its own organizational entity could be considered independent or objective for LIPA's oversight needs. Furthermore, a contractor's assessment of risk in order to establish an audit plan would not reflect their client's risk profile. Regardless of the service contractor performing audits, the products of any of these audit activities for the past three years, if any were performed by National Grid for National Grid, are unavailable.[24]

- In the past three years, five audits were performed in addition to LIPA's audited financial statements:[25]

  - Lock Box Audit
  - 2010 MSA Metrics Audit
  - 2011 MSA Metrics Audit
  - Efficiency Long Island (ELI) Audit
  - Payroll Tax Treatment Audit.

- Two other audits by the State Comptroller included: Debt Report and Overview of Contracts with National Grid.[26]

- Baker Tilly was engaged by LIPA to review the processes and calculations related to the MSA performance metrics reported by National Grid for the years ended December 31, 2010 and 2011, as discussed above. The scope of the engagements included three primary tasks:[27]

  - Review the metric baseline standards used by National Grid to report its 2010/2011 performance metrics and compare those standards to the baseline standards agreed upon between LIPA and National Grid.
  - Review inputs and calculations related to the 2010/2011 performance metrics for reporting accuracy.

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[22] DR 34
[23] DR 4
[24] DR 36
[25] DR 36
[26] DR 36
[27] DR 36

- Review and update metrics documentation with National Grid subject matter experts, as needed, to determine any process changes. Any significant process changes would be discussed with LIPA for approval and concurrence.

- For CY2011, the contactor survey portion of the customer satisfaction metric finished the year in the penalty range which controls 55 percent of the penalty for this metric, or $1,100,000. The Actual Meter Read Rate and Bad Debt Ratio were also in the penalty range but were partly offset by favorable performance for First Call Resolution. The net impact of the calculated penalty after offset is $1,000,000. Total penalties for the 2011 performance metrics are $2,100,000. National Grid requested relief from these penalties under the Force Majeure clause of the Management Services Agreement due to Hurricane Irene.

- In addition to the above, Navigant Consulting performed a Capital Projects Review in 2008. The final draft of this audit was dated February 6, 2010.[28] The results of this audit are presented in greater detail in **Chapter 10 – Capital Program and Project Planning and Management**.

- The Baker Tilly Audit of the ELI program identified numerous areas of weak controls. LIPA and National Grid have implemented some changes, including creation of a comprehensive policy and procedure manual for the ELI program.[29]

6.3.5 The oversight and control of third-party materials and services contracts performed by National Grid has also been weak and inadequate.

- National Grid performs materials and services procurement for LIPA and stated that third-party suppliers are monitored and controlled by the following:[30]

  - Key outside suppliers agree to terms and conditions for the services they are to provide including pricing details, schedule requirements, expectations in the quality of work to be performed, guarantees/warranties, and where applicable, formal Key Performance Indicators (KPIs).
  - Procurement also plays a role in this effort by compiling data to measure performance against KPIs; insuring KPIs are applied consistently across all contracts to which they apply; coordinating and/or participating in periodic contract review meetings with the supplier; and assisting and/or leading negotiations with the supplier to settle claims and contract disputes.
  - A supplier's performance, in those cases where KPIs have been measured over a period of time, is then factored into bid evaluations for future contracts. Procurement will not agree to the inclusion of KPI's in a contract unless these indicators are fair, measureable and structured to influence behaviors in suppliers that result in a safe work environment and quality output from the contract.

[28] DR 38
[29] DRs 36, 231 and 646
[30] DRs 46 and 50

- Materials and services contracts may specify price, schedule and quality expectations. However, National Grid's use of KPIs for these contracts has been very limited.[31]

  - Over a two-year period, National Grid reported the use of 2,447 contracts for over $363,740,000 in materials and services provided to LIPA. Some of these represented multiple line items that rolled up to a single contract.
  - National Grid has significantly overstated its program of contractor performance measurement. Only 12 contractors were reported using KPIs.

- National Grid's Construction Delivery and other constructing organizations, such as OH/UG Lines and Substation Maintenance, provide construction management supervision and are responsible for overseeing the performance of third-party contractors utilized to support the implementation of LIPA's major capital program. Supervisors oversee the contractor work force on a daily basis for compliance with the engineering design documents and specifications.

- LIPA and National Grid could not provide the following in a timely manner:[32]

  - Field inspection reports.
  - Progress inspection reports, whether documented by National Grid, LIPA, or another party.
  - Quality assurance reports.
  - Final completion reports or project completion documentation.

6.3.6 The MSA terms and conditions enhanced National Grid's profit potential by allowing resources covered by the annual fixed price operations and maintenance MSA fee to be used for "pass-through" expense reimbursement during storm response, major maintenance and capital improvement activities.

- Section 6.1 of the MSA addresses annual compensation for fixed O&M services fees, variable compensation, and escalation.

- Section 5.1(A) of the MSA covers Capital Improvements Generally, acknowledging that from time to time it will be necessary to make repairs and replacements to the T&D system that do not constitute routine maintenance. All such project costs constitute capital improvements, entitled to pass-through expenditures, billed monthly as incurred.

- Section 6.2 of the MSA covers pass-through expenditures that include: capital costs, claims and litigation, storm events, taxes, refunds, remediation costs, conservation and easements.

- Appendix 11 of the MSA defines "storm events" and payment obligations. All costs incurred by National Grid as a result of responding to and restoring the T&D system to a "system normal" status after a storm event, as well as any immediate follow-up

[31] DR 202
[32] DR 642

work performed in the five-day period commencing from the return to system normal status, and all subsequent follow-up work approved by LIPA, shall be paid to National Grid in addition to the Total Manager Compensation and charged against a storm reserve established by LIPA and the Manager (the Storm Reserve).

- A "Storm Event" is defined in the MSA as an event where (i) at least 15,400 customers are interrupted or (ii) at least 150 outage jobs are logged within a 24-hour period.

- National Grid charges all costs incurred to the Storm Reserve to: (a) make all repairs, replacements and other steps necessary or desirable to restore the T&D System to "system normal" state, and (b) for immediate follow-up work performed in the five-day period after "system normal" status has been achieved and all subsequent follow-up work approved by LIPA. A Storm Event ends when the system is returned to "system normal" status, after a threshold of less than 1,000 customers remain interrupted has been achieved and maintained for a period of eight (8) hours.

- Based upon this definition, LIPA experiences from 25 to 35 storms per year. Along with the five days of post storm response, National Grid can be performing pass-through work for a considerable portion of each year.

- As resources move from O&M activities to capital improvements or storm recovery, National Grid's O&M internal direct costs are reduced and the margin for profit increases under the MSA Total Manager Compensation. LIPA has not performed an audit to quantify the National Grid charges for resources used on capital improvements and storm restoration that are normally covered by O&M fixed fees.

6.3.7 MSA goals and results are measureable and verifiable; however, the "targets" were developed based on prior performance rather than industry standards or performance improvement targets, and are somewhat meaningless given the structure of the metrics. [33]

- Given the structure of the metrics, National Grid can fail to meet a performance target but not be penalized.[34] National Grid is considered to be in the "target" range as long as the performance is better than the penalty trigger and below the offset trigger.[35] However, the MSA does not refer to a range, but rather a single target.

- MSA targets for primary and RUD cable faults were developed based on limited data sets from 2005-2006. As part of its audits of National Grid's reported performance, Baker Tilley repeatedly recommended adjustment to the baseline for these metrics to accommodate more recent actual performance data, but LIPA did not update the baselines.[36]

[33] Appendix 5, Amended and Restated MSA
[34] This has happened on numerous occasions.
[35] Amended and Restated MSA, Appendix 5
[36] DR 37 and review of MSA Amendments

- Documentation of LIPA's approval of certain other agreed-to metrics such as capital cost per customer and worker safety does not exist. According to the Baker Tilly audits the baselines were verified by LIPA after-the-fact.[37]

- As shown in **Exhibit 6-3**, the performance targets for most MSA metrics did not change over time to drive continuous improvement.

  - Baker Tilly made a number of recommendations regarding other baseline calculations, the metric calculation methodology and other process improvements, none of which appear to have ever been implemented.[38]
  - Performance that consistently exceeds incentive triggers, particularly if by a large margin as is the case with the cable fault metrics (see **Exhibit 6-2** shown previously, and underlying data), can be indicative of targets that are set too low. No modifications were made to this metric.
  - The Days Sales Outstanding (DSO) target changed over time but the penalty trigger remained unchanged, resulting in no actual change from an incentive standpoint.
  - JD Power Survey targets were added in 2010 but were not designed to drive improvement over time and were set initially at a very low level despite performance issues in this area.

- Customer service performance targets are in some cases below industry standards. As examples:

  - The target for the Average Speed of Answer (ASA) is 168.9 seconds and the penalty is 213.9 seconds – over 3 ½ minutes. Typically the industry standard target is 80 percent of calls within either 60 or 30 seconds. The MSA ASA targets are lower than the service level targets National Grid uses in other states.[39]
  - The JD Power Customer Satisfaction targets represent 4th and 3rd Quartile performance for the Residential and Commercial Surveys, respectively. National Grid's performance does not fall into the penalty range unless its residential results are 16th or 17th of 17 participants for residential and 22nd or 23rd of 23 for commercial. As a result, National Grid can achieve its performance target while having overall customer satisfaction in the fourth quartile.

[37] DR 37

[38] DR 37 and 887. The same issues and recommendations appear year after year.

[39] See customer service chapter for additional discussion.

Exhibit 6-3
MSA Performance Metric Modifications 2006-2013

Type/Metric	2006 Target	Subsequent Changes	Notes
Non-Offset Metric			
CSI- Contactor	78.92%	Y	Targets and triggers more aggressive each year
CSI-JD Power Res.	N/A	Y	Added in 2010 – changed relative weighting in 2011 and 2012. Targets and triggers unchanged. Eliminated in 2013
CSI-JD Power Business	N/A	Y	Added in 2010 – changes relative weighting in 2011 and 2012. Targets and triggers unchanged
SAIDI	55.5 minutes	N	No change to targets or triggers
Customer Metric			
Actual Meter Read Rate	96.13%	N	No change to targets or triggers
Billing Accuracy	99.54%	N	No change to targets or triggers
DSO	32.29 days	Target only	Target more aggressive each year, but triggers unchanged
Bad Debt Ratio	0.46%	N	No change to targets or triggers
E-Bill Enrollment	20,477 customers	Y	Targets and triggers more aggressive each year
E-Payment	1,414,000 trans.	Y	Targets and triggers more aggressive each year
Call Answer Rate/ Average Speed Answer	93.5% 168.9 seconds	N N	No change to targets or triggers No change to targets or triggers
First Call Resolution (telephone survey)	68.8%	Y	Target 68.8% in 2006 and 2008, 70% in all other years. Offset trigger similarly dropped in 2008 and NG achieved offset
Operational Metric			
Work Plan Completion Index	Completion	N	Completion of O&M Work Plan Capital Work Plan and Corporate Initiatives in their entirety
Capital Cost per Customer	$176	Y	Varied over time (up and down)
Multiple Cust. Outages		Y	Targets and triggers more aggressive each year
SAIFI	14.5 months	N	No change to targets or triggers
CAIDI	66.3 minutes	N	No change to targets or triggers
Storm CAIDI	137.6 minutes	N	No change to targets or triggers
Worker Safety	5.14 accidents	Y 2007 only	5.14 target in 2006, 5.65 in subsequent years. No change to triggers
Planned Substation Maintenance	34 jobs	N	No change to targets or triggers
Primary Cable Faults	12.24 days	N	No change to targets or triggers
RUD Cable Faults	24.61 days	N	No change to targets or triggers

Source: Amended and Restated MSA, DRs 19, 25, 108, 412, 413, 434.

- Because the MSA does not clearly specify the calculation methodology or data sources,[40] it is possible that the method of calculation may result in seemingly better performance relative to potential industry benchmarks.[41] As an example, the LIPA call answer rate metric includes calls resolved by automated systems (Interactive Voice Response (IVR) for normal operations and 21st Century for outage reporting), resulting in a higher performance level than if automated resolution calls are not included. **Exhibit 6-4** provides an example using July 2012 data.

Exhibit 6-4
Answer Rate Calculation Methodology Comparison

Data	Rep Answered: 136,053 Rep Offered: 143,682 IVR Satisfied: 108,676 + 21st Century: 9,933 = Subtotal Automated: 118,609	
	Inclusive of IVR	**Exclusive of IVR**
Formula:	(Rep Answered + Automated Handled)/ (Rep Offered + Automatic Handled)	Rep Answered / Rep Offered
Calculation:	136,053+118,609)/ (143,682+118,609)	136,053/143,682
Results:	97.09 percent	94.69 percent

Source: DR 440, 442

6.3.8 The 18-23 performance metrics included in the MSA do not provide for adequate oversight of a contract of its size, complexity or risk.

- Eighteen to twenty-three metrics in a single tier, as in the MSA, cannot provide adequate visibility into the operations of LIPA. This number of metrics is insufficient from a management standpoint in both breadth of functions included and depth into key functional areas. An effective performance measurement hierarchy would require a dozen or so high level metrics reported at the executive level with increasingly detailed and comprehensive operational metrics as one moves further down the functional organization. Similarly, performance metrics would fully cover the enterprise's missions and functions.

- The MSA metrics are generally lagging indicators. Lagging indicators tend to measure results or outcomes (e.g., worker safety). Leading indicators tend to be drivers of the outcome (e.g., percent of employees attending safety training). Some measures can be both leading and lagging. As an example, customer satisfaction is generally considered a lagging indicator. Percentage of on-time appointments kept can be considered a lagging indicator but may also be a leading indicator of customer satisfaction.

[40] National Grid procedures developed in 2010 provide greater but not complete specificity.
[41] This is not intended to imply any violation of the MSA.

6.3.9 MSA metrics do not address efficiency or cost control.

- There is no mechanism within the MSA for LIPA to encourage or direct improvements in operational efficiencies or overall cost control on the part of the National Grid.

- While the fixed fee structure for O&M activities could result in National Grid reducing costs to increase profitability, there is no vehicle for LIPA to know what costs are being reduced or their potential impact on customers or operations.

- Under the MSA, cost reductions due to increased efficiency would not accrue to LIPA or affect the National Grid Total Compensation.

6.3.10 The MSA and the LIPA-National Grid structure tends to constrain performance improvements.

- National Grid stated that MSA metrics were designed to maintain a level of service for which National Grid was being compensated.[42] This position statement does not support continued improvement.

- LIPA routinely meets with National Grid and reviews performance. It may bring issues to National Grid's attention, identify performance issues and request that National Grid address performance deficiencies. However, LIPA contractually has no ability to direct National Grid or drive National Grid's performance. LIPA's approval of the annual budget serves as its only real tool under the contract to address operational deficiencies.

6.3.11 Not only does the MSA provide no incentives to the service provider to improve performance, the penalties for not meeting (the lower edge) of the target band are inadequate to drive behavior.

- National Grid is paid roughly $260 million per year under the MSA to operate the system (excluding pass through expenditures). Maximum annual potential MSA performance penalties were $7 million from 2006-2009 and $11 million thereafter, less than five percent of the annual payments at risk.

- Despite performance deficiencies in certain areas, actual penalties have been $1 million or less per year, as shown in Exhibit 6.2 (provided previously).

    - Calculated penalties for 2011 were $2.1 million; however, LIPA only invoiced National Grid for $500,000, as a result of National Grid's request for force majeure relief due to Hurricane Irene.[43]
    - The 2012 Baker Tilly audit has not been finalized, but initial calculations of the performance metrics for 2012 showed performance in the penalty range for some

[42] Fact verification submission by National Grid related to conclusion 6.3.7.
[43] DR 36, 762 and 763

annual metrics. National Grid has again asked for majeure relief due to Hurricane Sandy.

- Over time LIPA has modified some MSA performance incentives, as shown in **Exhibit 6-5**. In 2006 some of the performance requirements were actually made less stringent.

Exhibit 6-5
Timeline of MSA Performance Requirements

Agreement	Requirements
1997 MSA	• Performance incentives/disincentives were tied to achievement of seven metrics: reliability indices (2), worker safety, call answering, meter reading and accounts receivable performance, and sharing of PILOT payment refunds, and were capped at $7.5 million • Contract could be terminated without cure opportunity for failure for two out of three consecutive years to meet the minimum customer service and worker safety standards. Failure to meet the minimum reliability standard for both CAIDI and SAIFI in two out of three consecutive years for any of the geographic operating divisions was considered an event of default requiring cure opportunity.
2006 Amended and Restated MSA	• Replaced the original cost-plus structure with a "fee for service" structure. • Allowed for greater LIPA rights of access, including the right to designate up to four LIPA employees at the Manager's offices. • Modified the events of default not requiring cure to include failure to meet customer satisfaction performance metrics for three consecutive years, SAIDI for two out of three consecutive years (excluding force majeure). Worker safety was eliminated. • Substantially revised the performance metrics (18 metrics) designated as either an offset metric or a non-offset metric. Annual penalties net of offsets shall not exceed $7 million or an amount which would result in the Manager receiving less than the minimum compensation. Metric standards were set based on performance through September 30, 2005. • Added a requirement for the performance of a best practices review, with the scope determined in consultation with LIPA. • In the event that the Manager has unfavorable performance in any metric for two consecutive contract years, LIPA may request that the Manager conduct an internal best practices review related to that performance metric.[44] • Performance measures could be adjusted by mutual agreement following the best practices review.[45]
December 22, 2009 (Second Amendment)	• Added to/modified the performance metrics. The customer satisfaction performance metric penalty was increased by $1 million and JD Power Survey results were added to the metric calculation and the maximum penalty was increased from $7 million to $11 million. • Required National Grid to provide LIPA with bid documents and the results of its best practices review and implementation plan, and to commit to resolving concerns • Required National Grid to implement a governance process procedure; establish an accountability plan for improving customer satisfaction performance for all National Grid departments and senior managers that provide significant services under the MSA; develop a culture improvement plan; and a plan for the contactor survey samples. • Changed the first call resolution survey contractor.

Source: MSA and Amendments

[44] Amended and Restated MSA Section 4.4(B)
[45] Amended and Restated MSA, Appendix 5, 1(d)

- In 2008, National Grid failed to achieve satisfactory performance of the customer satisfaction metric for the third consecutive year. LIPA had the ability to impose the maximum penalty for non-performance by terminating the MSA contract; however, it did not do so.

- LIPA could have required National Grid to conduct an internal best practices review related to failed customer satisfaction performance in 2007, as allowed by Section 4.4(B) of the Amended and Restated MSA, but did not.[46]

6.3.12 Amendments to the MSA tied National Grid's employee compensation to contract performance. However, NorthStar was not provided details of the compensation plan to determine the level of compensation at risk or the extent of the ties.

- The 2010 Negotiated Settlement between LIPA and National Grid required National Grid to link executive and management compensation directly to improved customer satisfaction.[47]

- According to National Grid, its corporate annual performance plan performance is based on a combination of financial performance, individual performance and the results of metrics which include safety and reliability, customer responsiveness, stewardship and cost competitiveness.[48]

  - According to National Grid, the LIPA reliability metrics are captured in the goals for those employees serving LIPA. National Grid employees that serve the LIPA MSA also have other aspects of the MSA metrics built into their individual performance objectives which align with their particular functional area.[49] NorthStar was unable to validate this alignment.
  - While bonus payments for all eligible employees are to be tied to the achievement of broad OSA performance metrics, it is unclear how closely aligned specific functions are with the metrics for which they are more directly responsible.

- As discussed in **Chapter 4 – LIPA Organization and Executive Management**, LIPA management and personnel compensation are not linked to performance metrics.

- While targeted improvement initiatives have been undertaken, neither LIPA nor National Grid (on behalf of LIPA) has established continuous improvement programs.

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[46] DR 26
[47] Office of the New York State Comptroller, Long Island Power Authority Oversight of Contracts with National Grid, Report 2009-S-9 (DR 36)
[48] DR 399. NorthStar has not seen the performance evaluation forms.
[49] DR 399

- There are two performance improvement programs currently underway – the Customer Satisfaction Improvement Program (CSIP) and the Customer Satisfaction Action Plan (CSAT) designed to address specific customer service issues.[50] These programs are discussed in **Chapter 14 – Customer Service.**

- LIPA and National Grid conducted after action reviews following Hurricane Irene and Hurricane Sandy to identify areas that worked well during the event and provide suggestions for future improvements.[51]

- In the last three years National Grid has introduced four six sigma improvement initiatives: a data quality project, two billing projects and a project to eliminate incorrect customer refunds. Due to competing resource demands, work continued but these projects were discontinued as six sigma initiatives.[52]

6.4 Recommendations

Recognizing the Transition from the National Grid / MSA operational environment to the PSEG / OSA operational environment, NorthStar's recommendations to improve overall management of outside services, executive performance, operational performance and metrics are contained in **Chapter 8 – Transition and Management of the ServCo/OSA Organization**.

[50] DR 7
[51] DR 8, 267, 357
[52] DR 431. According to National Grid, some of these projects have been incorporated into different process improvement approaches and/or regular business practices. This has not been verified.

7. ENTERPRISE RISK MANAGEMENT AND STRATEGIC PLANNING

This chapter discusses LIPA's current enterprise risk management activities and the closely related corporate strategic planning processes.

7.1 Background

Enterprise Risk Management (ERM) is the process through which organizations identify the risks faced by their company, quantify and prioritize those risks, and proactively undertake activities to mitigate or manage those risks. Typically, the mechanism used to identify and monitor risks and risk mitigation strategies are referred to as a "risk matrix." Organizations will and should pursue a variety of risk mitigation strategies depending on the size, type and potential impact of the various risks. For example, organizations may purchase insurance policies against the risk (the traditional risk management approach), introduce processes and training to protect against the event occurring (e.g., field safety protocols and training), develop contingency plans (e.g., for storm response), require credit checks to verify suppliers capabilities to deliver, purchase financial hedges, or any number of other activities to protect the organization against risks. Some risks may be determined to be so minor to the organization, or have such a low probability of occurrence, that organizations reasonably do nothing and monitor the risk for any changes.

For organizations that provide essential services, ERM becomes part of the corporate culture, with risk considerations embedded in all that is done within the organization. For LIPA, the existence of a strong ERM culture is particularly important, since key services provided by LIPA to its customers are actually provided by outside service providers. We would expect to see a strong ERM focus within LIPA and a clear directive and close coordination with its outside service providers to identify, define, and mitigate/manage risks between the two organizations. Among other factors, there should be a clear statement of responsibility for risk management and close accountability for any risk events. As in any organization, the risks -- financial and operational -- associated with decisions, and options for managing those risk, should be a clear part of corporate decision-making.

Strategic planning provides a roadmap of a company's overall direction and plans for the future, and how it expects to achieve that future. A company's strategic planning process should include identification of trends and risks, and should be closed linked to its ERM process, the development of tactical/operational plans and the budgeting and financial planning processes. A strategic planning process can be a highly structured and complex process, involving outside consulting resources and detailed data collection, modeling and output materials. This level of sophistication is not essential and many large organizations develop their strategic plans using in-house resources and basic business tools. However, successful strategic planning processes require clear and strong leadership from both the Executive and Board levels, an active process to involve and obtain input from all parts of the organization, an ongoing commitment to the plan, and explicit monitoring of progress towards the goals. The relationship between planning horizons and overall corporate planning elements is illustrated in **Exhibit 7-1.**

Exhibit 7-1
Strategic Planning Components

Planning Horizon	Overall Direction	Qualitative Factors	Quantitative Factors	Performance Management
Near-Term (12-18 months)	Corporate Mission & Vision	Tactical Plans	Operating Budgets	Annual Targets
Mid-Term (2-5 years)		Likely challenges Have-to and want-to activities Multi-year projects	5 year capital plan Net income projections Financing plans	Measurable progress towards meeting mid-term objectives
Long-Term (5-10 years)		Horizon opportunities and threats	Monitoring possible big needs	Monitoring
Risk	Risk Assessment and Monitoring			

Source: NorthStar Consulting Group, Inc. 2009.

LIPA's use of outside service providers for delivery of its core services means that some key elements and inputs into a typical utility strategic plan are outside of the direct knowledge of the Authority staff. Thus, the LIPA strategic planning process should include explicit solicitation and inclusion of input from the outside service providers. The outsourcing of key services could be a barrier to the Authority's ability to implement programs related to services provided by contractors to achieve strategic goals. Additionally, LIPA's financial situation, with an extremely high amount of debt and minimal "head room" in rates, provides significant constraints on the long term strategic options available to the Authority.

7.2 Evaluative Criteria

- Is the breadth and scope of the ERM process within LIPA consistent with good practices?
- Are suitable processes employed by LIPA to assess and rank risks to the organization, including physical, financial and operations dimensions?
- Does LIPA include its key outside service providers in its ERM process?
- Does LIPA have a formalized process (e.g., ERM) for assessing the risks versus benefits of capital plans?
- Does LIPA have and comply with appropriate procedures and practices related to the scope of this audit, e.g., internal controls, internal audit function and any voluntary compliance with the Sarbanes Oxley Act?
- Are the results of the ERM incorporated into the strategic plans and other corporate decision-making at the executive and Board level?

- Are LIPA's overall strategic planning processes sufficiently comprehensive in scope and development?
- Has LIPA suitably defined the purpose and mission of the organization?
- Does LIPA have an in-depth understanding of where the organization is now and where it needs to be in the future, who its customers are, and when it is time to shift to a new direction and reevaluate its purpose and mission?
- Has LIPA adequately defined the specific long-range and short-range positions it wishes to occupy?
- Has LIPA effectively established objectives, formulated its strategic plan, followed through with its strategic plan, and assured its activities are consistent with the defined purpose of the organization?

7.3 Findings and Conclusions

7.3.1 LIPA does not have any formalized ERM process, and the informal documents provided by the Authority do not constitute an appropriate process for managing overall corporate risks.

- LIPA identifies three categories of risk: operational, financial and commodity. The Authority pointed to the Operating and Financial and Audit Committees of the BOT as providing oversight regarding appropriate levels of risk.[1] According to LIPA:

  - Operational risk is categorized in terms of system and supply planning leading to reliability of delivery and supply and is mitigated through the supply and system planning processes.
  - Financial risk is linked to budgeting and debt management, with the budget process used to keep risks within tolerable bounds; and

- Commodity risk is addressed through the Energy Risk Management process, overseen by the Energy Risk Management Committee.[2]

- The Risk Management Policy provided by LIPA addressed only commodity price risk.[3] Additional materials were provided relating to the Authority's compliance with financial regulatory requirements. LIPA is not subject to Sarbanes Oxley requirements.[4]

- LIPA's risk matrices consist of the New York State risk assessment template, completed on a department basis by some LIPA departments. Completed templates were not available or were inadequate for certain critical departments, specifically

1 DR 55
2 The Energy Risk Management program is addressed in Chapter 17 – Energy Supply Planning.
3 DR 56
4 Review of compliance with debt covenants and any other financial reporting or compliance requirements was not part of the scope of this audit, and NorthStar has not reviewed these areas.

system planning, supply planning, power management, finance and accounting (although Accounts Payable and Payroll were provided).[5]

- There are considerable differences in the level of detail and manner in which the templates are completed, indicating no guidance was provided for their completion.

- While there were some attempts to review the contents of the template,[6] the risk matrices are not integrated with one another, are not used within the departments, and are not incorporated into the budgeting process. The sole role of these matrices is for annual certification regarding the internal control structure of the Authority.[7]

7.3.2 LIPA does not include its key service providers in any risk assessment activity, and National Grid does not have risk matrices for the functions and services it provides to LIPA.

- None of the state assessment templates included operations performed by the National Grid organization, (e.g., maintenance, capital projects, meter reading, new service installations). The inclusion of Customer Service and Energy Efficiency Programs in the templates provided is due to the LIPA personnel who oversee and coordinate with the National Grid organization in those areas.[8]

- The material provided in response to a request for risk assessments by the National Grid organization consisted solely of a system operating and stability study.[9]

7.3.3 LIPA does not have an effective Internal Audit function to provide independent assessment of the risks and risk mitigation processes either within the LIPA organization or in any of its key service providers and vendors.

- As discussed in **Chapter 4 – LIPA Organization and Executive Management**, until the end of 2012, LIPA did not have an Internal Audit department or any Internal Audit staff.[10] As a result, the Authority does not have any tools or processes for assessing the effectiveness of any existing operational practices designed to monitor and mitigate risk within LIPA or National Grid.

- LIPA does apply standard credit risk mitigation practices such as letters of credit to its major vendors, and manages its own credit exposure related to fuel supply and fuel price hedging transactions through standard financial credit management practices.[11]

7.3.4 LIPA does not prepare an enterprise-wise strategic plan. The few departmental operating and tactical plans that are prepared are not integrated.

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5 DR 57
6 DR 57, tracking spreadsheet
7 DR 754
8 Various interviews
9 DR 244 and DR 871
10 DR 34
11 DR 801 and DR 888

- According to LIPA, its Strategic Plan is represented and guided by the Mission and Vision statements and the Performance Measurements.[12]

- The job description for the Director of Strategic Planning identifies implementation of a strategic planning process as the first element of the job; actual job responsibilities have been diverted to emergency response planning and management, and more recently involvement in the identification and transition to the new service provider.

- Requests for LIPA's strategic plan were answered with references to the Electric Resource Plan (ERP) 2010-2020, which provides a ten-year plan for electric supply and transmission to meet the goals of reliability, cost control, energy efficiency, renewable energy and greenhouse gas emissions.[13] The ERP does not address other aspects of utility operations, such as distribution level needs, customer service, information technology, human resources/personnel and rate strategies.[14]

- LIPA additionally identifies the move to a new business model as its strategic plan, both in discussions and indirectly in the names of the numerous analyses conducted for the Authority:[15]

  - Lazard report addresses "Strategic Options"
  - FTI study titled "Strategic Organizational Review
  - Brattle Group study titled "Strategic Organizational Options"

- Department-specific multi-year plans were identified in the areas of Customer Service, Rates, Information Technology, and Financial (Debt Reduction). National Grid provided a document addressing system operational planning in response for any strategic plan for the LIPA operations.[16] The common aspects of these plans were: specification of the LIPA mission and vision (although often with different wording) and acknowledgement of the need to address rate impacts.

- LIPA did begin a broader planning effort towards the end of 2012. However the initiative was not pursued due to uncertainty regarding LIPA's future structure.[17]

7.3.5 While LIPA's stated Mission, Vision and Values are adequate, there are some aspects of these public statements that are troubling.

- Companies tend to place the emphasis of its daily work and long-term investments on those items that appear most important to its leadership, and the Mission and Vision statements are the most public and clear specifications of those priorities. LIPA's current Mission and Vision Statements are shown in **Exhibit 7-2**.

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[12] DR 41
[13] DR 41 and DR 42. Additional information on the ERP is provided in Chapter 18 – Power and Fuel Supply Management
[14] The ERP does include rate impacts as one evaluative criteria, but not an overall rate impact strategy.
[15] DR 27 and DR 290,
[16] DR 649, DR 749 and DR 242
[17] DR 343 and various interviews

Exhibit 7-2
Mission and Vision Statements for LIPA

Our Mission

Our mission is to provide highly reliable and economical electric service to our more than 1.1 million customers in Nassau and Suffolk counties and the Rockaway Peninsula in Queens through our valued workforce with a commitment to superior service, accountability and transparency in all of our operations, while being recognized as a leader in the advancement of efficiency and renewable energy.

Our Vision

The Long Island Power Authority strives to be:

- The most reliable overhead electric utility in the state
- The industry leader in the advancement of energy efficiency & renewable energy
- A responsible steward of the environment
- A catalyst for economic development in the region
- Focused on superior customer service
- The best managed electric utility in the state

Source: LIPA website and DR 3

- In the LIPA Vision Statement, the relative placement of the elements, with energy efficiency and renewable, environmental stewardship and economic development listed before customer service, is troubling.
  - While the listing order is likely not an intentional reflection of the priority of customer service relative to energy efficiency and renewables, it is reflective of the apparent focus of the Authority.
- LIPA's stated values of transparency, leadership and accountability[18] are acceptable, if generic corporate values. The fourth value – reliability – would typically be taken to mean "consistent" in a value list, but likely means "reliable electric service" in this instance.
- LIPA identified certain "Cultural Objectives" (See **Exhibit 7-3**), however the role of these four elements in the Authority's operations or planning is not specified, and they were not referenced or provided in response to any requests for planning guidelines or employee training materials.

[18] DR 41

Exhibit 7-3
LIPA's Cultural Objectives

Source: DR245

- The Mission Statement was developed by the CEO and approved by the BOT in 2010. It has evolved slightly from the initial version, including adding the specifics of the Authority's size and service territory, and changing from "superior customer service" to "superior service."[19] The Mission Statement does not mention safety, something that is frequently included in utility mission statements.

7.3.6 While LIPA developed proposed measurements by which the achievement of its goals could be evaluated, these measurements do not constitute a strategic plan nor assure its activities are consistent with the defined purpose of the organization.

- LIPA developed proposed measurements by which its performance and progress towards achievement of its goals could be evaluated, as required by Section 2824-a of the New York State Public Authorities Reform Act (PARA) of 2009.[20]

- LIPA's performance goals developed to meet PARA requirements are shown in **Exhibit 7-4**. They relate generally to LIPA's mission and include many of the MSA performance metrics.

  - On their own, these measures do not constitute a strategic plan.
  - The performance measures that LIPA established pursuant to PARA do not specify how performance will be measured or evaluated.

[19] Comparison of DR 3, DR 41, DR 245 and other LIPA documents
[20] Public Authorities Reform Act of 2009, http://www.abo.ny.gov/abo/Chapter506of2009.pdf. Measurements to be developed on or before March 31, 2010

Exhibit 7-4
LIPA's PARA Performance Goals

Goal	Performance Measure(s)
Provide reliable and economical electric service	System Average Interruption Duration Index (SAIDI) System Average Interruption Frequency Index (SAIFI) Customer Average Interruption Duration Index (CAIDI) Reliability comparison to other similar NYS utilities using SAIFI and CAIDI Capital Projects Reasonableness of Price
Provide superior customer service	Performance metrics contained in LIPA Management Services Agreement with its contractor National Grid LIPA's performance/rating according to JD Power and Associates' Electric Utility Business Customer Satisfaction Study and LIPA Contactor Survey Use of Communications Systems Services for Special Customers Financial Assistance Programs Online/Web-Based Services On-Bill Customer Usage Information
Accountability	Compliance with and timely submission of required reports and related governance and disclosure filings Board Committee Activities Voluntary Public Information Sessions Training of Staff and Trustees
Transparency	Website information availability, including meeting webcasts Compliance with all aspects of New York State's Open Meetings Law Public Dissemination of Pertinent Customer and Other Information
Being a leader in the advancement of efficiency and renewable energy	Efficiency Long Island Performance Report Performance compared with other utilities as reported in the American Public Power Association and Large Public Power Council reports and as compared to other New York utilities Participation and cooperation with other governmental agencies

Source: http://www.lipower.org/pdfs/company/trans/LIPAperformance.pdf

- Several of the goals in LIPA's Vision Statement do not have corresponding performance metrics - a responsible steward of the environment, a catalyst for economic development in the region, or the best managed utility in the state. While LIPA has environmental and economic development programs there are no performance measures.

- There are no stated, beginning-of-the-year targets, standards or goals for any of the PARA performance measures, except indirectly for the MSA performance measures, discussed in **Chapter 6 - Contract Management and Performance Measurement**.

- LIPA's end-of-year annual performance evaluation reports also do not clearly indicate what the goal for the year was or if there was a goal in all areas. In some cases, it is difficult to determine if LIPA believes its performance in certain areas was on target.

  - For example, performance against the reasonableness of price goal indicates rates have been stable, but are high compared to others.
  - LIPA's discussion of the capital plan performance indicates: "LIPA completed its capital investment plan in 2011 with the investment of $233 million into its T&D system" and cites selected projects completed. The inference is that merely completing the plan equals performance.[21]

- Performance against many of the measures is either subjective or not clearly measurable/quantifiable, nor does LIPA use milestones. For example:

  - Reported performance in the areas of communications systems, services for special customers, financial assistance programs, or on-bill customer usage information is just a listing of services available to the customer and activities during the year.
  - Performance against the Board Committee action goal is a list of issues reviewed by the BOT. Similarly, Training of Staff and Trustees provides a list of available staff training seminars without any indication of the level of participation.
  - Performance against the measure Website Information Availability is a discussion of the website features.

- Based on interviews with senior management, it appears the annual evaluations are developed to comply with PARA rather than as part of a comprehensive, robust performance management process.[22]

7.3.7 LIPA does not have a strategic planning process. Long-term planning is conducted informally within the Executive Team and does not meet the expectations for a strategic planning process.

- LIPA's Executive Team meets weekly, both in formal meetings and informally, and it is through these meetings and discussions that strategic issues are identified and addressed. [23]

- Some consideration of programmatic opportunities and tradeoffs is performed as part of the annual budgeting process.[24] However, the lack of a strategic plan for LIPA's operations precludes any ability to assess capital projects, new programs, operating

[21] See Chapter 11 - Capital and O&M Budgeting for further discussion
[22] Various interviews
[23] As there is no documentation of the planning process, NorthStar interviewed members of the Executive Team and other key personnel with planning responsibilities to identify how decisions with long term or strategic implications are made.
[24] DR 755

budgets, and major strategic investments and decisions against agreed-upon future goals and desired outcomes.

- O&M and capital budgets are largely established on one-year basis, with tradeoffs and programmatic decisions made based on the immediate situation and current perspectives of the then-members of the Business Review Committee (BRC).[25]
- While the capital budgeting process includes some assessments of benefits of projects and risks of not implementing an activity, there is currently no formal incorporation of ERM into the capital budgeting process.
- LIPA's budget process for 2013 included a request for each LIPA department to identify key risks.[26] This request was independent of the State risk matrices discussed earlier. In fact the individual responsible for the budget process did not remember their existence.

• These informal processes do not meet any of the expectations for a strategic planning process, as shown in **Exhibit 7-4**.

Exhibit 7-4
NorthStar Strategic Planning Preferred Practice Checklist

NorthStar Preferred Practices	Yes	No
Directed by the CEO.		X
Has significant senior management involvement.		X
Reviewed and approved by the Board of Directors.		X
Coordinated and monitored by dedicated resources.		X
Processes and responsibilities are well-documented and understood by key management.		X
Process assures appropriate bottom-up input.		X
Addresses a wide range of issues.		X
Is responsive to dynamic changes in the operating environment.		X
Includes detailed functional and departmental performance goals.		X
Links goal attainment to incentive compensation.		X

7.3.8 LIPA's outsourcing of core service functions to a third party does not remove, and in fact increases, the need for a comprehensive risk management process and strategic plan for the long range, overall provision of electric service to Long Island (including consideration of, for example, customers and employees).

[25] See Chapter 11 –Capital and O&M Budgeting for additional discussion of the budgeting process.
[26] DR 755

- Regardless of outsourcing decisions, LIPA retains the ownership of the electric service assets on Long Island, along with the fiduciary responsibility and the obligation to serve customers.

- There is limited understanding and no consensus within LIPA of management's responsibilities for the long term needs of Long Island electric consumers, other than from a supply standpoint, as evidenced by the lack of any type of strategic plan.

- The lack of a comprehensive risk assessment for all aspects of the provision of electric service are further indications that LIPA believes it has little long-term responsibility for these aspects of the operation.

- LIPA Management and BOT appear to have defined their areas of responsibility as those activities under their direct control, and have in most part abdicated to its third party provider any responsibility for long-term planning for the electric assets and for the responsibility to provide electric service.

7.3.9 To date, LIPA management has not taken appropriate steps to identify, rank, and manage the risks inherent in operating an electric utility nor to develop an overall strategic plan for the provision of electric service to Long Island.

- This is particularly troubling as most of the critical operations facing possible physical risks and in need of strategic direction are not under LIPA's direct control, and current service provider also does not have an appropriate risk management system nor a strategic plan for the utility operations.

- The preliminary Internal Audit (IA) Plan, prepared in May 2013, has as its first activity, the development of a risk assessment, to include financial reporting and operations activities of National Grid, LIPA and the transition and then to prepare a risk-based audit plan is to be prepared. The IA Department was intending to use outside resources to prepare the risk assessment.[27]

- Without a strategic plan, it is extremely difficult for LIPA to determine whether the budgets and plans prepared internally, let alone those submitted by its outside service provider and other contractors, are consistent with the long-term needs of the electric service system on Long Island.

- It is highly likely that both risk assessment and strategic planning are areas where the processes, tools and expertise of PSEG-LI can facilitate a significant improvement in risk identification, quantification, planning and management.

7.4 Recommendations

7.4.1 Undertake a comprehensive, coordinated enterprise risk assessment study (in conjunction with PSEG-LI) that covers all aspects of the provision of electric service, regardless of what entity performs the function. The study should include industry

[27] DR 748

recognized tools and processes for evaluation of the magnitude and likelihood of risk events, leading to the development of a prioritization of risks and the development of appropriate risk mitigation strategies commensurate with the risk of loss and the cost to mitigate. Develop processes to maintain and regularly update the risk assessment.

7.4.2 Develop (internally or with contractor assistance) a strategic plan to address the totality of the provision of electric service to Long Island, based on a comprehensive assessment of, for example, the needs and risks associated with the service territory, its customers, fiduciary obligations, and market impacts and uncertainties. The strategic plan should include identification of strategies to achieve the goals of the plan and measurement of progress. With the plan in place, prioritization and evaluation of on-going and proposed new programs and initiatives, capital projects and other major decisions should be considered and evaluated in the framework of their support for the long term plan.

7.4.3 Develop a comprehensive set of corporate performance measurements (in conjunction with PSEG-LI) that are consistent with requirements of PARA, tied to the formal Enterprise Risk Management program and Strategic Plan, and include, as appropriate, performance of relevant service providers.

In developing the program, LIPA should consider the following:

- Specifically utilize defined, measurable targets with performance reported against the goals and targets
- Include performance metrics which address all key elements of LIPA's mission and goals.
- Adequately address potential operational, financial and service (including customer) risks.
- Include links with the employee evaluation process and compensation.
- Reflect any revisions to the LIPA structure.
- Encompass each of the major service provider contracts.

7.4.4 Strengthen the capabilities and commitment to Internal Audit within the Authority, including dedicating personnel with utility operations and auditing experience. Under the OSA, the need for qualified Internal Auditors who are able to develop an understanding of the details of the OSA agreement and other key service agreements will be critical to LIPA being able to effectively control and ensure compliance of the service providers.

8. TRANSITION AND MANAGEMENT OF THE OSA/SERVCO ORGANIZATION

This chapter discusses issues related to the management and performance of the ServCo organization business model and the OSA contract, based on LIPA's management of National Grid under the existing MSA, and other key contracts. The analysis presented here is based on the OSA executed by LIPA and PSEG-LI[1] on December 28, 2011, and the analyses and related plans prepared by PSEG-LI as of mid-June 2013. The impacts of the legislation enacted in July 2013 (the Reform Act) on the scope and structure of the OSA, LIPA, PSEG-LI or ServCo/ManageCo are not addressed here as they were not known as of June 21, 2013, the end of NorthStar's audit period. All references to the OSA refer to the December 28, 2011 document.

8.1 Background

The OSA between LIPA and PSEG-LI for operation of the LIPA system over a ten-year period modifies the performance measurement process that was part of the MSA, including the establishment of performance incentives and three tiers of metrics:

- Tier 1 metrics are those tied to the incentive calculation.
- Tier 2 metrics are those subject to active performance management programs
- Tier 3 metrics include those considered business management indicators that will be routinely monitored and reported, but are not included in Tiers 1 and 2. According to PSEG-LI, Tier 3 metrics may be more at the employee level.[2]

Under the OSA, PSEG-LI's potential incentive compensation pool is allocated among several key areas of performance as shown in **Exhibit 8-1**. No portion of the OSA incentive compensation pool is allocated to the Cost Management Category because PSEG-LI must achieve the Cost Management Performance Metrics to be eligible for incentive compensation in the other performance categories. Metrics are designated as either "improvement" or "maintenance" metrics with the level of compensation determined accordingly. Maintenance metrics represent those areas in which satisfactory performance levels are currently being achieved. Improvement metrics are those in which current performance is unsatisfactory. **Exhibit 8-2** provides a listing of the OSA maintenance and improvement metrics.

[1] The OSA is between LIPA and PSEG, Long Island, LLC, a subsidiary of PSEG established for the purpose of performing the obligations of the OSA. PSEG has partnered with Lockheed Martin to establish and manage certain support systems, such as IT and Finance functions. For convenience, the term PSEG-LI is used to refer to PSEG Long Island, LLC and Lockheed Martin collectively as the new outside service provider. Additional background on the OSA is provided in Chapter 3.0 – Background on LIPA.

[2] IR 59

Exhibit 8-1
OSA Proposed Incentive Compensation Weighting

Performance Category	Performance Goal	Weighting
Cost Management	Achieve the spending levels at or below the Capital Budget while completing the Capital Work Plan in all material respects, and achieve the spending levels at or below the Operating Budget while completing the Operating Work Plan in all material respects.	Threshold
Customer Satisfaction	Achieve high levels of end use customer satisfaction.	40%
Technical and Regulatory Performance	Provide safe, reliable power supply in a manner compliant with applicable safety, environmental and other regulations.	30%
Financial Performance	Meet LIPA's financial performance needs.	30%

Source: OSA Appendix 8.

Exhibit 8-2
OSA Metrics

Minimum Performance Metrics	Improvement Metrics	Maintenance Metrics
Operating Budget and Work Plan Capital Budget and Work Plan	JD Power Residential JD Power Business After Call Surveys Personal Contact Survey ASA Abandon Rate Web Transactions Worker Safety AMRR Timely Billing DSO BDR	SAIDI SAIFI CAIDI Major Event Day/Storm CAIDI ELI – Cost per kW ELI – Achieved Load Reduction

Source: OSA Appendix 8.

The OSA also establishes a considerably more complex system to incentivize improved performance by PSEG-LI. Each metric is assigned base points, target ranges, and performance minimums which vary by metric. For the maintenance metrics, the target range was to be established by the Transition Committee. **Exhibit 8-3** provides a summary of the calculations process for maintenance metrics.

Exhibit 8-3
Amount of Performance Incentive – Maintenance Metrics

Performance Level	Incentive Range
Above Target Range	Over 100% of base points
Within Target Range	100 % of base points
Below Target Range but Above Minimum	0% of base points but not considered failure
Below Minimum	0% of base points and considered failure

Source: OSA Appendix 8.

For improvement metrics, a baseline is to be developed based on 2013 actual performance and targets are established to drive performance toward acceptable levels over a period of time ranging from 5 to 10 years. Targets are generally set based on first quartile industry performance. PSEG-LI earns greater incentives the faster it achieves targets for these metrics.

If PSEG-LI achieves only one of the Cost Management Performance Metrics (e.g., capital or O&M but not both), it is eligible for a maximum of 50 percent of the incentive compensation. Similarly, the performance incentive pool in any category is to be reduced by 50 percent if PSEG-LI fails to achieve minimum performance levels for the same metric, or by 100 percent if PSEG-LI fails to achieve minimum performance of two or more metrics in that category, for any two of three consecutive years unless the minimum has been met in the current year.[3] Failure to earn at least 70 percent of the Customer Survey Metric points or the minimum SAIDI level for two of three years results in a forfeiture of 100 percent of the incentive compensation for the Contract Year and a penalty payment by PSEG-LI to LIPA of five percent of the fixed Management Fee for that year.

As of May 2013, the Tier 1, Tier 2 and Tier 3 OSA performance metrics were still under development and not available for NorthStar review.[4] Similarly, final calculations, peer groups and performance level targets had not been developed.[5] According to PSEG-LI and LIPA, the intention was to implement the metrics in a manner as close as possible to the description stated in the OSA.[6] PSEG-LI and LIPA have agreed to the following changes in the performance metrics set forth in the OSA:

- The parties will agree to appropriate targets as appropriate benchmark data is not available for the following metrics: After Call Survey – Residential; After Call Survey – Business; and, Personal Contact Survey.
- Actual Meter Read Rate (AMRR): Performance metric will be revised as necessary to reflect continuation of bi-monthly meter reading.
- Days Sales Outstanding (DSO): Calculation will be based on year-end values to be consistent with available benchmark data sources.
- Bad Debt Ratio (BDR): Definition will be revised to be year-end A/R write offs per $100 of billed revenue to be consistent with industry practice for benchmarks.

[3] JD Power Residential and Commercial Survey Results and the Personal Contact Survey operate as one metric
[4] DR 445 and DR 446
[5] Various DRs including 448, 449 and 454
[6] DR 446

In addition, the parties have agreed to develop the targets based on data available as of October 2013 and adjust the preliminary values in early 2014, as necessary to reflect actual baseline and benchmark data for the full year 2013.[7]

8.2 Evaluative Criteria

The evaluative criteria addressed in this chapter have been extracted from several elements of the management audit Request for Proposal, principally those related to Executive Management, Organization, Outside Services, and Performance Measurement.

- Has LIPA identified "lessons learned" from the National Grid MSA and other key outside suppliers and incorporated appropriate changes into the PSEG OSA?
- Does the ServCo model represent appropriate spans of control, lines of responsibility, and efficient utilization of resources with no duplication of services? Does it represent lessons learned and improvements over the existing operating structure?
- Are the major functions in the new ServCo model properly staffed with personnel with sufficient utility experience to be able to assess the operational effectiveness of the outside service provider? Is the staffing of the ServCo by source: LIPA, PSEG, Lockheed Martin, appropriate?
- Are the functions, roles, reporting relationships, and responsibilities of each party in the ServCo model: LIPA, PSEG and the ServCo itself clearly identified and proper for that party?
- Does the organizational structure of the ServCo provide clear authority, responsibilities and duties of the Joint Operating Committee?
- Has LIPA identified the processes, systems, and controls needed to assure successful implementation of the ServCo business model?
- Is the ServCo Transition well planned, and are there adequate plans to monitor organizational performance subsequent to implementation?
- Will the new OSA with PSEG include performance requirements and penalties/incentives, and will they be established based on any lessons learned from the current agreement?
- Are there additional performance measures or indicators that are needed to facilitate the corporate mission, objectives and goals? For example, in addition to lagging indicators, are there appropriate leading indicators, metrics and measures that will help improve performance?

[7] DR 446

8.3 Findings and Conclusions

8.3.1 The OSA uses almost identical language as the MSA to recognize LIPA's ultimate responsibility for the Long Island electric system and assets:[8]

- LIPA's responsibilities under the MSA include:

  - MSA 4.5: Rights and Responsibilities of LIPA. As the owner of the T&D System, LIPA retains the ultimate authority and control over the assets and operations of the T&D system.
  - MSA 3.1 (F): Right of Access. LIPA shall have the right of access to the T&D system and common facilities at all times on an unannounced basis for audit and oversight.
  - MSA 4.16 (D): Books and records upon which the reports and statements required by Article IV shall be made available by the Manager to LIPA for audit by LIPA or LIPA's designated independent auditor.
  - MSA 4.16 (E): In addition to financial audits, LIPA may audit the Manager's and its Affiliates books, records, accounts, facilities, equipment, technology and other materials used in performance of services.
  - MSA 4.18: Capital Asset Control. In each contract year the Manager shall conduct an audit of the capital improvements made in the prior contract year

- LIPA's responsibilities as highlighted in the OSA include:

  - OSA 4.4: Rights and Responsibilities of LIPA. As the owner, lessor or controlling entity of the T&D System, LIPA retains the ultimate authority and control over the assets and operations of the T&D system and the right, consistent with the Contract Standards and this Agreement, to direct the Service Provider, in connection with the performance of the Service Provider's obligations under this Agreement.
  - OSA 4.2 A.3.c: Auditing of fees, rents, revenues, internal audit, external audit, and audit rights to all information relating to all services provided; and
  - OSA 5.4: Covers LIPA's Right to Review and Audit.

8.3.2 The range of services to be provided by PSEG-LI under the OSA is comprehensive and virtually identical to the services provided by National Grid under the MSA.

- **Exhibit 8-4** identifies which entity was responsible for primary functions associated with the operation of the Long Island electric system under the MSA and under the OSA.[9] In both the current situation and the future ServCo business model, LIPA's role is primarily oversight of the performance of service provider; execution of certain activities (e.g., procurement, contracting and Human Resources(HR)) for its

[8] DR 4, Contracts
[9] DR 1 and DR 4

own operations. In a few cases, such as power and fuel supply, LIPA was an active participant in the operating function with support from National Grid.[10]

Exhibit 8-4
Organizational Functions and Service Contract Responsibilities

LIPA Organizational Functions	Role Under MSA		Role Under December 28, 2011 OSA	
	LIPA	National Grid	LIPA	PSEG-LI
Executive Mgt. and Governance	Primary	none	Shared (JOC)	Shared (JOC)
Environmental Affairs	Oversight	Monitoring	Not specified	Not specified
Community & Gov. Affairs	Primary, but transferred to NG following Sandy	Assumed following Sandy (major storms only)	Support	Primary
T&D Operations and Maintenance	Minimal	Primary	Budget approval, then minimal	Primary
T&D Capital Projects	Budget approval, then minimal	Primary	Budget approval, then minimal?	Primary
Budgeting	Oversight, Approval	Primary	Oversight, Approval	Primary
Legal	Primary	For NG Functions	Not specified	For ServCo functions
Legislative Affairs	Primary	None	Not specified	Not specified
Finance	For LIPA functions	For NG Functions	For LIPA functions	For ServCo functions
Internal Auditing	None	Included	Not specified	Primary
Controller	Primary	None	Primary	None
Risk Management (Insurance)	Not specified	Not specified	Not specified	Primary
A/P, A/R, Payroll, Accounting	For LIPA functions	For NG Functions	For LIPA functions	For ServCo functions
Power Markets, Fuel, Supply	Primary	Support	Primary	Support
Energy Efficiency	Oversight	Primary	Oversight	Primary
Renewable Energy Programs	Oversight	Primary	Oversight	Primary
Human Resources Management	For LIPA functions	For NG Functions	For LIPA functions	For ServCo functions
Procurement and Contracting	For LIPA functions	Primary for operations	For LIPA functions	Primary for operations
Information Technology	Oversight	Primary	Oversight	Primary
Customer Service	Oversight	Primary	Oversight	Primary
Communications, Call Center	Minimal	Primary	Oversight	Primary
CIS, billing, collections	Minimal	Primary	Oversight	Primary
Regulatory, Rates, Pricing	Primary	Support	Primary	Support
Emergency Preparation & Restoration	Oversight	Primary	Support	Primary

Source: NorthStar review of MSA and December 28, 2011 OSA

[10] The respective roles of LIPA and PSEG-LI have been modified as a result of the recent Legislation. These modifications were not finalized as of the end of the audit period and are not addressed here.

- Regardless of whether services are performed by LIPA or a contracted service provider, LIPA retains ultimate responsibility for results and effectiveness, and must have appropriate resources to meet its responsibilities.

- To effectively manage its outside service provider over such a broad range of services, LIPA must have access to necessary skills and core competencies.

- Additionally, LIPA must receive accurate and timely information on system performance and operational activities, and the information must be presented in a manner that enables efficient and effective evaluation of the results and identification of trends and possible issues.

- As discussed in **Chapter 4 – LIPA Organization and Executive Management** LIPA needs to obtain or develop increased utility and management skills, as well as more effective operational performance reporting systems.

8.3.3 Many Long Island electric customers have been dissatisfied with LIPA storm preparation and response/recovery. However, the MSA and OSA agreements are very similar in this regard and no incentives are tied to performance during storms.

- Contractual language in the MSA and the OSA regarding storm response and recovery are similar in their event definition and in payment terms for storm costs.[11]

- The OSA does not provide any incentives to efficiently and effectively respond to storms.

  - Within the OSA, Section 4.2 Operations Services states that PSEG-LI will be responsible for developing and implementing business continuity, disaster recovery and emergency response plans.
  - Section 4.2 further states that the emergency response plan must include provisions for:
    - Timely reporting to LIPA in the event of a storm or other such emergency
    - Storm monitoring and mobilization of the workforce, including mutual support crews
    - Coordination with media, fire, police and government agencies
    - Customer communications, including all inbound and outbound customer communication systems
    - Monitoring of T&D system conditions
    - Repair and replacement of any parts of the T&D system damaged by the storm
    - Public safety
    - Complete restoration of the T&D System to pre-emergency conditions

[11] DR 4

- PSEG-LI is also required to conduct periodic drills to test the validity of its emergency response plans and strategies and conduct post-event analyses and incorporate lessons learned from drills and actual events to improve the overall state of readiness.

- Procedures for the handling of costs related to a storm are contained in OSA Section 5.2 Pass-Through Expenditures.

  - "Pass-Through Expenditures" related to a storm include wages, salaries, benefits, pensions and other post-employment benefits of PSEG-LI's workforce, as well as materials, supplies, spare parts, vehicles, purchased services, and other subcontractor costs.

- Section 5.3 Storm Costs requires LIPA to set aside a storm reserve fund to cover these costs.

- Appendix 9, Definition of Storm Event and Operation of Storm Reserve, provides appropriately detailed procedures related to accounting for, substantiating and invoicing of storm costs.

- Nonetheless, nowhere does the OSA address the efficiency or effectiveness of PSEG-LI's emergency response efforts or provide any parameters for evaluating storm activities.

- For complete text on storm events and storm costs, storm definition and the payment mechanism, as well as similarities between the MSA and OSA, specific sections are identified in **Exhibit 8-5**.[12]

Exhibit 8-5
MSA and OSA Storm Definitions and Responsibilities

Item	MSA	OSA
Storm Definition	Appendix 11	Appendix 9
Storm Restoration	4.1(C) 4.2(B)(5)	4.1(C) 4.2(A)(4)(e)
Storm Costs	6.2(A) 6.4 Appendix 11	5.2 5.3 Appendix 9

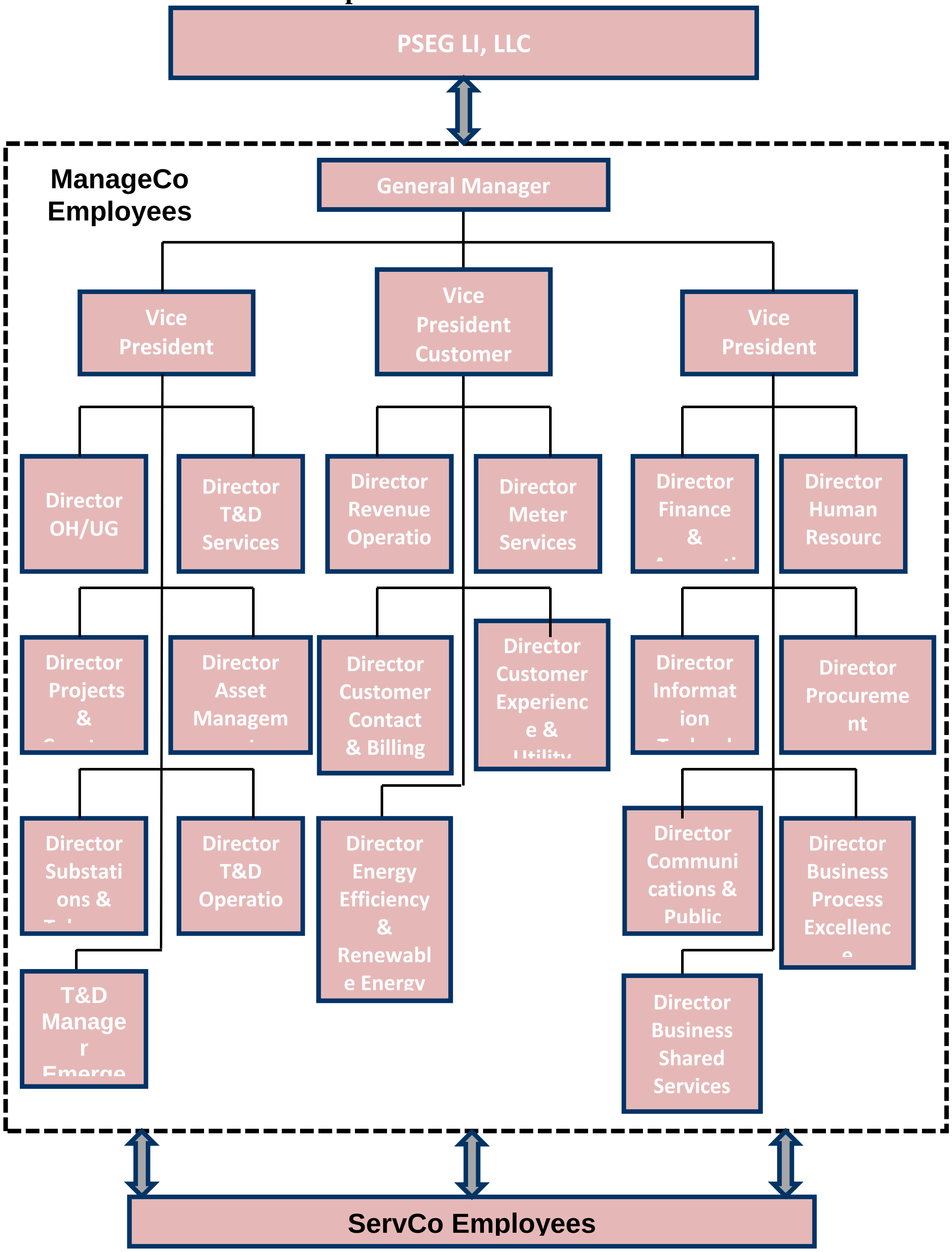
Source: DR 4, Review of MSA and OSA

8.3.4 PSEG-LI has largely adopted the current National Grid Long Island organizational units under the ServCo model.

- The planned PSEG-LI organization structure as of April 2013 is shown in **Exhibit 8-6** (itentical to **Exhibit 3-5)**.

[12] DR 4

Exhibit 8-6
Proposed PSEG-LI Structure



- The ServCo structure provides for dedicated employees and eliminates the current bundling of gas and electric operations. Without LIPA's prior approval, ServCo may not engage in any business or activity other than to provide Operations Services pursuant to OSA.[13]

- The planned structure assumed that functional areas currently part of LIPA will remain within LIPA. In particular, the following key functions are presently not part of the current ServCo structure:

  - Resource planning, power supply and fuel management (LIPA's current Power Markets Group),
  - Actual fuel procurement and power markets management (provided under contracts with CEE and PACE),
  - Finance and debt management,
  - Energy price risk management (both the LIPA execution activities and the risk advisory role provided by PACE),
  - Regulatory and NYS relations and legislative affairs, and
  - Interface with NYISO and other reliability and power coordinating organizations.

- PSEG-LI's review of existing processes and its resulting transition plans addresses only the functional areas and services specified in the OSA which were summarized in **Exhibit 8-4**, above.

- To the extent that the Legislation results in an expanded scope of services to be provided by PSEG-LI through ServCo, significant effort will be necessary for PSEG-LI to identify current status and conduct activities required to transition the services to the ServCo structure and PSEG-LI management.

8.3.5 Under the provisions of OSA, LIPA and PSEG-LI would have provided oversight to PSEG-LI and ServCo operations via the Joint Operating Committee (JOC). It is unclear how the oversight that was intended for this committee will be provided under terms of the recent legislation.

- Under the OSA Section 4.6: Governance, Joint Operating Committee, LIPA and PSEG-LI were to establish a JOC consisting of LIPA and PSEG-LI representatives that would have general responsibility for governance, oversight and coordination of PSEG-LI and ServCo's activities, including strategic direction, quality of services, rapid resolution of certain conflicts or issues, monitoring performance of operations services, changing performance metrics, approving the work plans (and any necessary modifications thereto) and adopting recommendations to amend or adjust the operating budget, the capital budget and the energy efficiency budget as might be needed during a fiscal year.[14]

[13] OSA, p. 22
[14] OSA, pp. 26-27

- Organizational, reporting, coordination and operating relationships between PSEG-LI and LIPA, including development of a charter and operating guidelines for the JOC were in the process of development and refinement during the audit period.

- The Legislation has significantly affected the relative organizational responsibilities, functions, staffing, and oversight role of LIPA and the existence of the JOC. Hence, there are many questions unanswered in terms of the governance and oversight of PSEG-LI and the ServCo business model.

8.3.6 While the revised operating model and OSA reflect some lessons learned from the MSA, in its present form the OSA would not resolve or eliminate the challenges LIPA has had with its service provider in the past.

- The OSA eliminates the fixed fee payment structure of the MSA. Operational costs are treated as a pass-through which should provide greater visibility to the costs incurred by PSEG-LI.[15] While the OSA improves the focus on costs and efficiency and may allow LIPA and PSEG-LI greater latitude to evaluate and implement performance improvement trade-offs, LIPA must provide the motivation and value review for continuous improvement as all costs are reimbursed.

- The OSA includes a more comprehensive performance management program with improvement targets and performance incentives/penalties.

  - PSEG-LI is able to earn an incentive as well as be assessed a penalty against the fixed component of the Management Services Fee based on its performance.[16] The incentive compensation pool represents $5.44 million, annually, relative to a management fee of $36.3 million, or 15 percent. The potential penalty is five percent.[17] The effectiveness of these financial incentives/penalties to influence PSEG-LI behavior is unknown.

  - The OSA introduces cost management and financial performance metrics which were lacking in the MSA. Failure to achieve the cost management metrics means PSEG-LI is not eligible to earn any incentive compensation or may only be eligible to earn 50 percent.

- The OSA metric categories are largely the same as they were in the MSA. The JOC would have had the ability to revise the performance metrics based on changes in LIPA's business conditions, the desire to re-focus performance on other aspects of operations, actual performance levels, capital investments, major system implementations, staffing considerations or other reasons. According to the OSA, such revisions may include:[18]

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[15] PSEG is paid an annual management services fee of $36.3 million in 2011 dollars

[16] OSA, p. 19

[17] OSA, p. 33 In no circumstance shall the annual amount of Incentive Compensation earned by the Service Provider exceed the lesser of (i) the Incentive Compensation Pool, or (ii) 20% of the total Management Services Fee for such year.

[18] OSA, Appendix 8, pp. 7-8

  - Modification of the minimum performance level, the target performance level, or change in the points assigned to the subject performance metric.
  - Reassignment of performance metrics among the designated Performance Categories and tiers, creation of new performance metrics, or elimination of existing performance metrics.
  - In particular, the JOC could modify the parameters of a maintenance metric if business or technical conditions indicate a need, or move a maintenance metric to Tier 2. After performance of an improvement metric reaches the established target level, the performance metric may be:
    - modified to establish a new improvement target level;
    - switched to the maintenance metric design with appropriate parameters; or
    - assigned to Tier 2 at the discretion of the JOC.

- If PSEG-LI fails to meet a minimum performance level for a Tier 1 metric in any year, it must prepare a corrective action report and plan.

- The JOC was envisioned to address these issues but its function was not completely formalized. With the recent legislation, it is not clear how these types of adjustments and revisions to the performance metrics will be handled.

8.3.7 The extent to which the metrics in the OSA will provide improved tracking and monitoring of the service provider's performance or give LIPA appropriate information to effectively monitor the overall operations of the electric system and meet its responsibilities remain unclear.

- Although LIPA and PSEG-LI tend to cite an increase in the number of metrics included in the OSA compared to the number in the MSA, the actual metrics are largely the same. **Exhibit 8-7** provides a side-by-side comparison of the metrics in the MSA to the Tier 1 metrics in the OSA.

- For improvement metrics, a baseline is to be developed based on 2013 actual performance and targets are established to drive performance towards acceptable levels over a period of time ranging from 5 to 10 years. PSEG-LI earns greater incentives the faster it achieves targets for these metrics.

- Targets are generally to be set based on first quartile industry performance. LIPA is largely relying on PSEG-LI for input into appropriate Tier 2 and 3 metrics and targets against which the PSEG-LI performance will be assessed. No analyses have been conducted to determine the cost of achieving a first quartile performance, nor to prioritize any particular aspect of performance for more or less aggressive improvement strategies. Additionally, LIPA has not compared the proposed performance metrics or targets with PSEG-LI's performance in the PSEG New Jersey operations.

- **Exhibit** 8-7

Performance Metric Comparison – OSA and MSA

Category	OSA Metrics	MSA Metrics
Cost Management		
Operating Budget and Work Plan	Tasks completed within operating budget	Work plan completion index (no cost consideration)
Capital Budget and Work Plan	Tasks completed within capital budget	Work plan completion index (no cost consideration) Capital cost per customer
Customer Satisfaction/Financial Performance		
JD Power Residential	Five specific questions – none overall satisfaction	Overall satisfaction
JD Power Business	Five specific questions – none overall satisfaction	Overall satisfaction
Contactor Survey	Two contact center surveys (residential and business) One non-contact center survey	One survey
Meter Reading and Billing	AMRR Billing timeliness	AMRR Billing accuracy
Contact Center	ASA Abandon rate	ASA Answer rate\ First call resolution
Collections	DSO BDR	DSO BDR
Web Transactions	12 specific types of transactions completed	E-billing enrollments E-payment transactions
Technical and Regulatory		
Reliability	SAIDI, SAIFI, CAIDI Major event day CAIDI	SAIDI, SAIFI, CAIDI Storm CAIDI Multiple customer outages Planned substation maintenance backlog Primary cable faults RUD cable faults
Safety	Worker safety	Worker Safety
Other		
ELI	Cost per kW per year Achieved load reduction	

Source: MSA and OSA

- The actual targets for the OSA performance metrics (Tiers 1, 2 and 3) had not been established as of May 2013, so NorthStar is unable to comment on their adequacy in addressing LIPA's mission, objectives and goals or providing necessary information on the overall system operations.

- LIPA indicated that the parties have agreed to develop the targets based on data available as of October 2013 and to adjust the preliminary values in early 2014 as necessary to reflect actual baseline and benchmark data for the full year 2013.[19]

8.3.8 PSEG-LI will need to transform not only a number of programs, policies and procedures, but also the culture of the existing personnel that will transfer to ServCo to meet its performance goals.

- Under the OSA, the services to be performed by PSEG-LI include "Continuous Improvement," which is defined as:[20]

  - Assisting LIPA in the development and administration of research and development, the goal of which is to increase operational efficiency and effectiveness and improve maintenance practices;
  - With LIPA's participation and approval, establishing and conducting a continuous improvement program designed to enhance the Service Provider's performance, operational efficiency and LIPA's cost effective delivery of services to customers; and
  - Monitoring industry advancements and technological changes in the operation, maintenance, repair and expansion of transmission and distribution systems, including customer care and related services, by electric utilities and recommending improvements in current programs and practices for LIPA's consideration.

- Other chapters of this report have identified shortcomings of the existing policies, procedures, operations, and control mechanisms related to, for example, customer service, communications with customers and other stakeholders, project planning and management, determination of value for services, risk assessment and management, and storm response. Achievement of improved performance for Long Island consumers will require improvements in these areas.

- To a large extent, LIPA's operations have been ignored by National Grid and LIPA's customers have not received the benefits of other National Grid corporate level process improvement initiatives. For example, National Grid uses a comprehensive "Playbook" to develop and manage its capital projects in other jurisdictions. However, the National Grid Long Island project management group was unaware of the document.

- National Grid's Long Island employees exhibit a dedication to performing their tasks to the best of their ability, yet there are no processes in place to encourage front-line employees to pursue process improvements, creative solutions, or outstanding customer service focus.

  - Internal process improvement programs are not apparent, where employees are encouraged to make suggestions for improvements in a specific process and

[19] DR 446
[20] OSA, p. 16

recognition and some reward is given for improvements that provide broad benefits by reducing costs or time.

- Links between individual and corporate performance and compensation are minimal and not directed by LIPA.
- The reward or recognition for outstanding performance or customer service is not apparent.
- There has been little innovation in work processes and records maintenance; many of the processes used by National Grid Long Island groups are the same as were used at LILCO many years ago.

- Much of the ServCo workforce will be "lifted and shifted" from the current National Grid Long Island organization and existing culture. PSEG-LI will have to instill a continuous improvement culture in these employees.

8.3.9 The proposed compensation plan for ServCo employees reportedly links performance and compensation; however, as the program has not yet been finalized or implemented, NorthStar cannot verify the linkages.

- National Grid's Long Island employees are reported to have some corporate-type goals in their performance plan. However, NorthStar did not review any specific individual plan so it is not known how large an impact this might be.

- Under the OSA, the JOC would have authority over guidelines for determining employee and earnings eligibility, scorecard goals, results, and the size of bonuses for the salary bands.[21]

- Depending on the employee's salary band, employees were to be eligible for an incentive bonus between 5 percent and 30 percent of their base salary as shown in **Exhibit 8-8**.

Exhibit 8-8
Draft Proposed ServCo Incentive Compensation Structure

<table>
<tr><th>Salary Band</th><th>Bonus Target</th><th>Bonus Max</th><th>Basis</th></tr>
<tr><td>C</td><td>25%</td><td>30%</td><td>30% financial (15% for ServCo and/or PSEG-LI)
30% Scorecard Results Customer Satisfaction, Safety and Reliability
40% individual performance</td></tr>
<tr><td>D</td><td>15%</td><td>22.5%</td><td rowspan="3">50% Scorecard Results for Customer Satisfaction, Safety and Reliability
50% individual performance</td></tr>
<tr><td>E</td><td>10%</td><td>15%</td></tr>
<tr><td>F</td><td>5%</td><td>7.5%</td></tr>
</table>

Source: DR 318

- While bonus payments for all eligible employees were to be tied to the achievement of broad OSA performance metrics, it is unclear how closely aligned specific functions are with the metrics for which they are more directly responsible.

[21] DR 318

8.3.10 As currently structured, the OSA and the ServCo business model do not address the LIPA management shortcomings related to the oversight and control of National Grid under the MSA.

- **Chapter 4 – LIPA Organization and Executive Management** identified a number of shortcomings in the current LIPA Management structure, including a lack of tenure and utility management experience and minimal understanding of the depth and breadth of its responsibilities for the provision of electric service on Long Island. **Chapter 6 – Contract Management and Performance Measurement** discussed how LIPA has evidenced minimal oversight and control over National Grid under the MSA.

- Changing the business model from one where some services are provided on a shared basis within the service provider's larger organization to one where all services reside on a standalone basis within the ServCo structure increases the likelihood and availability of data, timely reports, and access to supporting information and customized analysis. It does not, however, change the need for LIPA's management to request the relevant information and analysis and understand the import of the data and reports provided.

- Establishing three tiers of performance metrics may provide LIPA with more data, however for that data to provide useful information for management and direction, it must be the right information, focused on the right functions from across the operation, and presented in a manner that allows management to identify trends and verify performance. LIPA must understand what information should be provided and how to interpret it for management purposes.

- Setting performance targets at the first quartile seems appropriate, especially for an organization whose customer satisfaction numbers are at the bottom of the fourth quartile. However LIPA does not have information on the cost and rate implications of achieving these targets.

- Whether the OSA provides sufficient improvement in "leverage" for LIPA from that in the MSA remains to be seen. LIPA did not have the tools (contractually or financially) to direct National Grid's operational focus or to require improvements where LIPA (or LIPA's outside auditors) deemed change necessary. Theoretically, LIPA can withhold payment to PSEG-LI if inappropriate costs are submitted for reimbursement. However, the reality of the payment methods and timing, along with LIPA's historical reluctance to force change, limits the impact of this contract provision.

- While the ServCo staffing plan includes internal auditors plus third-party auditors,[22] these auditors will not provide LIPA and its BOT with an independent assessment of PSEG-LI's compliance with contract terms or of ServCo's operational compliance with policies and procedures.

[22] DR 2, ServCo Organization Charts as of October 16, 2012.

8.4 Recommendations

8.4.1 Recommend the adoption by PSEG-LI of all recommendations in this audit that are within the scope of PSEG-LI's contract, development of implementation plans and strategies to achieve the recommendations in a timely manner, and that the BOT be provided with quarterly written updates on progress towards achieving implementation.

8.4.2 Recommend to the DPS that an evaluation of the implementation of all recommendations contained in this report be performed in the next management audit.

8.4.3 Within the first year of the OSA, conduct (internally or with contractor assistance) a thorough, technical review of the OSA metrics (Tiers 1, 2 and 3) to fully document the basis for the metrics, key drivers and relationships, leading/lagging nature, benchmarks and performance at other utilities, and possible data and reporting issues. Develop a process for monitoring industry trends and regular updating of benchmarks and comparable performance for comparison with PSEG-LI performance.

The review should be performed with an eye towards ensuring/determining, to the extent possible within the OSA, the following:

- Performance metrics facilitate proper oversight.
- Performance issues can be identified early in the process, brought to LIPA's attention and addressed proactively.
- Sufficient flexibility to develop and implement performance improvement initiatives and hold PSEG-LI accountable for achieving performance improvements.
- Ability to modify the targets or the metrics to drive continuous improvement.
- Metrics address key areas of risk.
- Relative weightings are appropriate.
- LIPA understands how the metrics will be calculated and what data is and is not included.
- The current level of complexity is necessary and adds value.
- The Tier 1 metrics adequately address all critical performance areas and provide executive management with adequate visibility into PSEG-LI's performance.
- The Tier 1 metrics are adequately supported by the Tier 2 and Tier 3 metrics and appropriate linkages exist.
- The performance evaluation process for management and employees is adequately tied to the Tier-level metrics.
- The benchmark panel is appropriate and the method by which the panel members calculate and report performance is consistent with the methodology to be employed by PSEG-LI.
- Performance target levels are sound and drive appropriate performance levels.

8.4.4 Develop performance measures for emergency response and include them in a future revision of the OSA or its metrics.

- Lessons learned documents from the two recent major storms experienced by LIPA (Irene and Sandy) included a large number of recommendations for improving storm restoration efforts and management of emergencies. LIPA should draw upon some of these recommendations to find appropriate performance measures.

- LIPA should also set targets for some of activities that can be expected to always be a part of an emergency response effort, such as:

  - Initial global estimated time of restoration (ETR) for the LIPA system.
  - Regular updates and revisions of global ETR.
  - ETR's by substation or circuit.
  - Regular communication with media, government officials and regulators.
  - Ramping up staffing of the customer call center.
  - Acquisition of mutual assistance crews.
  - Restoration progress.

- Reimbursement of restoration costs should be based, in part, on achieving these goals.

8.4.5 Significantly improve LIPA's in-house internal audit capabilities. Strengthen the reporting relationship and communications between the Director of Internal Audit and the Finance & Audit Committee of the BOT. Develop the Internal Audit annual audit plan based on the enterprise risk assessment. Obtain access, in conjunction with PSEG-LI, for LIPA's Internal Audit to appropriate records and documents within the ServCo and PSEG-LI organizations.

9. SYSTEM PLANNING

This chapter covers LIPA's T&D transmission and distribution system planning to satisfy load requirements while maintaining a high level of reliability at the lowest cost.

9.1 Background

LIPA's power delivery system is comprised of bulk and sub-transmission systems, substations and a local distribution system. As defined by the New York Independent System Operator (NYISO), "bulk" transmission includes LIPA's 345 kV and 138 kV systems while sub-transmission includes the 69 kV, 33 kV and 23 kV systems.[1] LIPA owns 1,366 miles of transmission and sub-transmission lines and 181 substations.[2]

LIPA's transmission system has seven interconnections with its neighboring utilities:

- Two 345 kV interconnections with Con Edison. The first line connects LIPA's East Garden City Substation with Con Edison at its Sprain Brook Substation in Yonkers. The second line connects LIPA's Shore Road Substation to Con Edison at its Dunwoodie Substation also in Yonkers. These lines have a combined rating of 1,290 MW and provide access to the NYISO's bulk power system.

- Three 138 kV interconnections: There is one tie to Northeast Utilities which is three submarine cables into Northport which has a combined capacity of 428MW and allow LIPA access to the New England Power Market. The other two are ties to Con Edison which connect LIPA's Valley Stream to Con Edison's Jamaica Substation and connect LIPA's Lake Success Substation with Con Edison's Jamaica Substation. They have a combined contractual capacity of about 286MW.

- Two High Voltage Direct Current sub-marine interconnections: The first interconnection, the Neptune Cable, is from First Energy's Sayreville Substation in New Jersey to LIPA's Newbridge Road Substation. It is rated at 660 MW and provides access to the Pennsylvania-New Jersey-Maryland Interconnections (PJM) power market. The second interconnection, the Cross Sound Cable (CSC), is from New Haven Connecticut to LIPA's Shoreham Substation. It is rated at 330 MW.[3]

LIPA's service territory covers two jurisdictional planning areas: the Zone K demand area and the Long Island Control Area (LICA) demand area. Zone K is a planning region within New York State, and transmission planning for this region is coordinated with the NYISO in development of the State's Gold Book.[4] LICA is located within Zone K. LICA represents an adjustment of Zone K demand for municipalities within Zone K that have self-serving generation resources, energy efficiency, and co-generation facilities.

[1] DR 63, page 4
[2] DR 543, page 5
[3] DR 543 page 5
[4] The Gold Book is an annual planning product for the States' resource and transmission supply.

The LIPA Primary Distribution System is comprised of over 13,000 miles of 13kV and 4kV circuits (1,107 circuits).[5] LIPA's distribution system is approximately 70 percent overhead and 30 percent underground circuits.[6] Distribution circuits originate at circuit breakers connected to the distribution substations in the system. The circuits are made up of main line conductors connected in an open loop arrangement to one or more adjacent circuits and branch line conductors that are connected to the main lines through fuses.

The circuit mains have various sectionalizing devices to isolate faulted conductors and to facilitate the transfer of customers to adjacent circuits. These devices include, automatic sectionalizing units, automatic circuit reclosers, ground operated load break switches and stick operated load break disconnects. The primary circuit mains are generally designed to operate as part of a radial system but in specific instances, where a higher degree of reliability is desired; they are designed for automatic throw-over or network operation. Primary lines that branch off the mains are equipped with fuses at the point of connection to keep the mains in operation when branch line faults occur.

LIPA has two types of low voltage secondary network service. Area networks are supplied from two or more dedicated primary circuits with no other distribution load connected. Spot networks are normally supplied from two or more primary circuits that also supply other distribution load.

The recent increase in storm activity in the northeastern United States, especially the two extreme weather events that affected LIPA's territory in 2011 and 2012 (Irene and Sandy) have brought into focus the need for increased reinforcement and upgrading of the electric distribution infrastructure. System hardening, for purposes of this report, is defined as physical changes to the electric T&D infrastructure in order to make it less susceptible to storm damage, such as high winds, flooding, icing or other storm related damage. System hardening improves the durability and stability of the T&D system, allowing the system to withstand the impacts of severe weather events with fewer outages. It also improves the utility's capability to recover quickly from damage to its T&D system or to any of the external systems on which they depend.

Storm hardening is more than tree trimming, the installation of stronger poles, or installation of underground facilities. It is a process of identifying long-term system needs, planning for a wide variety of solutions, integrating them with other system needs and optimizing with available resources. System planning is the nexus of a storm hardening program.

While LIPA Generation Planning is responsible for providing capacity and energy for its full service customers, T&D system planning must also plan for the following users of the T&D system:

- Choice Customers, who receive power from independent energy marketers and utilize LIPA's transmission and distribution systems for delivery.

[5] DRs 554 and DR 63, page 4

[6] http://www.lipower.org/pdfs/company/papers/TDguidelines08.pdf

- Wheeling Customers, municipal and other government agency customers who receive hydro-electric power from the New York Power Authority (NYPA) and utilize LIPA's T&D system for delivery.
- Generation Interconnections to local generating facilities, including renewable installations within LIPA's service territory. Planning must be conducted to determine the system impacts from the addition of new generation.
- Co-generation facilities for whom LIPA may provide back-up service and the use of LIPA's delivery system.

The primary objectives of system planning are to satisfy load requirements while maintaining a high level of reliability at the lowest cost. LIPA's goal in transmission system planning is to design a system that provides adequate capacity between generation sources and load centers at reasonable cost with minimum impact on the environment. Aging infrastructure, resource conservation, energy efficiency programs, and a decline in customers and sales due to economic slowdown and competitive alternative providers all increase the need for up-to-date, accurate and dynamic system planning. Proper system planning integration should produce an optimal investment roadmap for all stakeholders, including ratepayers, generators, transmission owners, NYISO and LIPA itself.

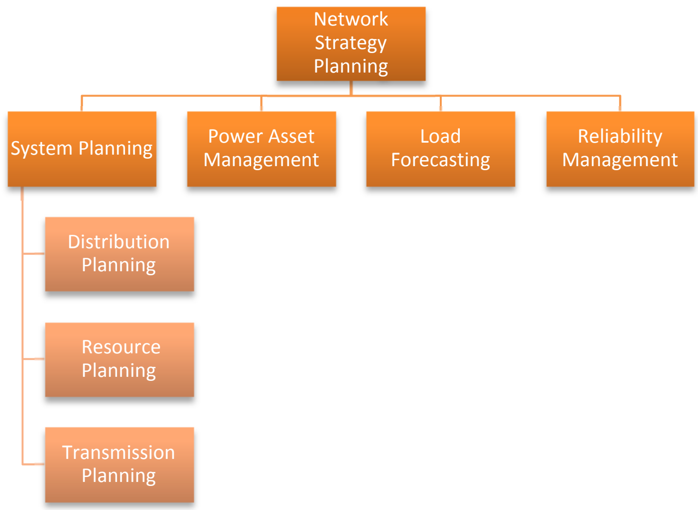
The adequacy of system planning must be evaluated for the service area as a whole in view of the pertinent reliability, regulatory, and load requirements. A thorough, well-designed system plan is critical to making cost-effective decisions. The plan should identify existing and potential system reliability deficiencies, estimate the likely cost of improvements and evaluate economic trade-offs of improved reliability compared to incremental system costs.

Transmission and Distribution Planning is conducted by National Grid as part of the MSA. National Grid's Network Strategy Planning organization provides all of the system-related planning functions for LIPA, as shown in **Exhibit 9-1**.

9.2 Evaluative Criteria

- Do the infrastructure planning and engineering functions operate effectively?
- Does LIPA have appropriate priorities, guidance and other instructions for evaluations, tradeoffs and decision-making including:
  - Asset condition and management process
  - Using input from the asset health review process
  - Linking asset management decisions (e.g., predictive failure analyses) to improve reliability and performance?
- Does LIPA/National Grid develop accurate system forecasts which are used in identifying infrastructure requirements?
- Are other load and infrastructure factors such as advanced metering and energy efficiency initiatives given appropriate consideration in the planning process?
- Are the needs for major projects identified, developed and justified adequately?
- Are the processes and criteria for making decisions regarding replace vs. repair, including how the overall construction program planning process is affected, documented, adhered to and appropriate?

Exhibit 9-1
Groups involved in Network Strategy Planning



- Are the planning processes for reliability versus new business trade-offs and regional versus central planning dynamics appropriate?
- Are benefit/cost analyses and risk analysis considered in the decision-making process?
- Are the specific types of benefit/cost and risk analysis methodologies used appropriately?
- Are tradeoffs optimized with respect to the replacement of older technology with newer technology and the resulting effect on the useful lives and depreciation assumptions of the existing infrastructure, cash flow and system reliability?
- Are load forecasts, resources, and distribution loads integrated and reconciled periodically?
- Does LIPA appropriately analyze reliability benefits for their customers versus short- and long-term rate effects?
- Does LIPA's/National Grid's long-term system planning function address land availability, right-of-way, land use and environmental siting constraints, and do they establish a context for future public interaction on specific projects?
- Is LIPA's system planned, designed, constructed and maintained to minimize the potential effects of a major storm including adequate investments in infrastructure hardening and resilience measures such as equipment and line improvements and vegetation management?

9.3 Findings and Conclusions

9.3.1 LIPA's system reliability has been excellent for many years showing that planning and engineering functions operate effectively.

- LIPA reports two reliability metrics to the New York State (NYS) Public Service Commission (PSC): SAIFI and CAIDI.

  - SAIFI measures on average, how many times a customer is interrupted within a single year. It typically is measured in 'per year', but also can be measured in 'number of months' between customer interruptions (used by LIPA and National Grid).
  - CAIDI measures on average, the length of an interruption. It is typically measured in hours (as in **Exhibits 9-2** and **9-3**) but can also be measured in minutes (as in **Exhibit 9-4**).

- Another commonly used reliability measure, SAIDI (System Average Interruption Duration Index), measures on average, the length of time of an interruption per customer.

- LIPA T&D system reliability ranks among the best in NYS electric utilities and has for many years. **Exhibit 9-2** provides the 5-year average reliability indices for New York as measured in SAIFI and CAIDI. Indices are shown with and without the inclusion of major storms.[7]

Exhibit 9-2
Five Year System Average Reliability Indices in New York (2008 – 2012)

Utility	Excluding Major Storms		Including Major Storms	
	SAIFI	CAIDI	SAIFI	CAIDI
Central Hudson Gas & Electric	1.22	2.35	2.19	8.74
Con Edison (radial system data)	0.40	1.93	0.78	22.07
Long Island Power Authority	0.73	1.21	1.23	7.40
New York State Electric and Gas	1.10	2.03	1.94	7.27
Niagara Mohawk (National Grid)	0.86	1.97	1.19	3.30
Orange and Rockland Utilities	1.07	1.72	1.71	11.92
Rochester Gas & Electric	0.73	1.80	0.97	2.60
Statewide[8]	0.57	1.89	0.91	8.86

Source: NYPSC 2012 Interruption Report

  - LIPA's performance both with and without major storms is high.
  - LIPA's worst performing CAIDI (including major storms) was in 2011 due in large part to Hurricane Irene.[9] In that year, LIPA experienced a CAIDI (including

[7] Electric Reliability Performance Report to the DPS 2012.

[8] Includes Con Edison total Network and Radial systems for state averages; Con Edison's Radial Systems are more comparable with the other utilities' overhead systems.

major storms) of 9.69 hours, still much less than Central Hudson Gas & Electric and Orange & Rockland Utilities who reported 15.95 hours and 15.32 hours, respectively.

9.3.2 System reliability is consistent across LIPA's service territory.

- **Exhibit 9-3** provides LIPA's historical reliability performance by division and system average. LIPA's system CAIDI and SAIFI is generally consistent across its four divisions.

Exhibit 9-3
Five Year LIPA System Reliability Indices
(Excludes major storms)

Division	Queens/ Nassau		Central		Western Suffolk		Eastern Suffolk		System	
	SAIFI	CAIDI	SAIFI	CAIDI	SAIFI	CAIDI	SAIFI	CAIDI	SAIFI	CAIDI
2007	0.637	1.00	1.152	1.36	0.835	1.16	0.902	1.13	0.898	1.20
2008	0.547	1.09	0.883	1.71	0.706	1.40	0.893	1.10	0.771	1.36
2009	0.600	0.98	0.995	1.39	0.639	1.07	0.687	1.06	0.737	1.17
2010	0.863	0.84	0.754	1.46	0.561	1.16	0.784	0.97	0.727	1.11
2011	0.821	0.27	0.825	1.29	0.651	1.14	0.753	1.07	0.755	1.14
2012	0.665	0.98	0.701	1.48	0.635	1.30	0.707	1.13	0.677	1.25

Source: DR 118 and DR 695

- Reliability is a measured performance requirement in the MSA. The following penalty-enforced annual performance metrics are specified in the MSA:[10]

  - Multiple Customer Outages (MCO) – number of customers in a rolling 12 month period that have experienced more than three non-storm related outages. National Grid incurs penalties above 96,069 customers. The penalty is $500,000.
  - SAIDI (excluding storms): National Grid incurs penalties when the annual average is above 68.9 minutes. The penalty is $ 1,000,000.
  - SAIFI (excluding storms): National Grid incurs penalties when the interruption frequency falls below 12 months. The penalty is $250,000.
  - CAIDI (excluding storms): National Grid incurs penalties when the annual average is above 75.6 minutes. The penalty is $250,000.
  - Storm CAIDI – is a measurement of the average service restoration time in minutes. National Grid incurs penalties when the annual average is above 221.1 minutes.[11] The penalty is $500,000.[12]

- **Exhibit 9-4** provides National Grid's performance against these system reliability metrics. Typically, National Grid has performed at levels better than the requirements of each metric. The one notable exception is in 2008, where National Grid exceeded the penalty threshold for CAIDI.

[9] Electric Reliability Performance Report to the DPS 2011.
[10] Excludes PSC Major Storms
[11] Excludes weather related events that cause more than 150,000 outages system wide.
[12] DR 4 MSA Appendix 5

Exhibit 9-4
LIPA Reliability Performance

	MCO[13] (Customers)	SAIDI (Minutes)	SAIFI (Months)	CAIDI (Minutes)	Storm CAIDI
NG Penalty Threshold	**>96,069**	**>68.9**	**<12.0**	**>75.6**	**>221.1**
2007	Base Year	64.4	13.4	71.8	107
2008	67,633	63.0	15.6	81.7	125
2009	47,449	51.6	16.3	70.0	97
2010	39,812	48.6	16.5	66.9	167
2011	46,527	51.6	15.9	68.3	112
2012	36,055	50.6	17.7	74.7	122

Source: DRs 4, 20, 118, 412 and 685

9.3.3 LIPA reliability metrics are calculated utilizing the same methodology as New York utilities regulated by the PSC.

- An established policy is utilized for documenting outages:
  - The outage management system (CARES) is used to diagnose the location of an outage.
  - Affected customers are determined by a process called "polygoning" where a dispatcher looks for a pattern of customer outages and groups the customers with the same assumed cause of outage. This function is performed by dispatchers in the Division control centers manually
  - A restoration team is dispatched and the following time metrics are recorded:
    - Dispatch time
    - En-route time
    - Onsite time
    - Outage restore time
    - Outage complete time (Time outage is cleared)
  - Outages are reviewed at the end of the day for irregularities.
  - Data is downloaded into the Electric Interruption Data System (EIDS).
  - Reliability metrics are developed utilizing the data in the EIDS.[14]

- LIPA conducts an annual independent audit of reliability metrics and reviews the calculations of SAIDI, SAIFI, and CAIDI.[15]
  - The 2010 audit verified that the reliability metrics were calculated correctly.
  - The 2011 audit found a small discrepancy in the calculation of SAIDI where a non-storm event was initially misclassified as a storm event. While this event was not during a storm, LIPA agreed that it should be excluded from the metric

[13] Value determined based on average of 12 months data found in DR 20.
[14] DRs 573 and 620 and State of New York Department of Public Service Case E 12-E-0288 June 2012 Report
[15] DR 574

calculations because restoration was prevented by order of the local authority. The calculation of 68.29 was correct.[16]

- The major storm exemption as specified in New York Codes, Rules, and Regulations (NYCRR) Title 16, Part 97 is utilized in LIPA's reliability calculations.[17]

- The "24 hour interruption of service" major storm exclusion offers the largest opportunity for a utility to alter its reliability metrics. During 2012, the 24 hour interruption of service exclusion was utilized on 13 instances. NorthStar conducted a detailed review of the storm occurring on July 7, 2012 to verify definitions and calculation methodology.

  - On July 7 and 8, 2012, a thunderstorm resulted in 8,961 customer outages.
  - One outage in the Central Division was caused by a down power line and the subsequent failure of a 1,500 kVA transformer bank.
  - As reported, 588 customers were interrupted and the average outage time was 283 minutes (over 4 hours). This event was excluded from "blue sky" reliability metrics based on the 24 hour interruption of service standard.
  - NorthStar reviewed the trouble tickets and verified that 588 customers were interrupted and that the average outage time was 283 minutes.
  - NorthStar verified that the transformer replacement did take over 24 hours to complete and that one customer was interrupted for over 24 hours.[18]

- NorthStar recalculated LIPA's 2012 SAIFI and CAIDI (excluding major storms) to include the 13 exclusions for 24 hours of interruption and found that LIPA remained among the most reliable utility systems (recalculated SAIFI=0.76 and recalculated CAIDI=1.50 compared to LIPA's reported values of SAIFI=0.68 and CAIDI=1.25).[19]

9.3.4 LIPA's system reliability benefits from a higher customer density than its neighboring New York State utilities.

- **Exhibit 9-5** provides the relative customer density of comparable NYS utilities based on service area in square miles and number of customers.

- NorthStar used customers per square mile as a proxy for customers per circuit mile to determine customer density. Utilities report primary and secondary distribution circuit miles inconsistently, prohibiting reliable customer per circuit mile comparisons.

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[16] DR 574 and fact verification.

[17] New York Codes, Rules, and Regulations (NYRCC) Title 16, Part 97, defines major storms as those either causing the interruption of service to over 10 percent of the customers in a service district or a storm related event causing an outage of greater than 24 hours. For PSC regulated utilities, calculations utilized for performance penalties exclude major storms.

[18] Discussions with PSC staff confirm that all customers associated with a single trouble, regardless of individual outage time, are included in the 24 hour standard if any of the customers were interrupted for over 24 hours.

[19] DR 118, 121, 695 and NorthStar analysis.

Exhibit 9-5
Customer Density

Utility	Customers	Service Territory (Square Miles)	Density (Customers per Square Mile)
Central Hudson Gas & Electric	300,541	2,600	116
Long Island Power Authority	1,110,853	1,230	903
Niagara Mohawk (National Grid)	1,500,000	21,000	71
Orange and Rockland Utilities	301,835	1,350	224
Rochester Gas & Electric	368,000	2,700	136

Sources:
http://www.chenergygroup.com/ourbusiness.html
http://www.lipower.org/company/powering/stats.html
http://www.fundinguniverse.com/company-histories/niagara-mohawk-holdings-inc-history/
http://www.oru.com/aboutoru/oruataglance/index.html (includes tri-state area)
http://www.dps.ny.gov/04M0159_RGE_annualreport_05.pdf

- A smaller service territory combined with higher customer density offers a number of advantages, including:
  - Shorter travel time from reporting locations to trouble spots
  - Improved repair and control coordination among crews
  - Increased spare parts and backup equipment coverage

9.3.5 Attention to worst performing circuits has improved system reliability.

- Two worst performing circuits lists are developed annually: one for vegetation management outages, and another for conversion and reinforcement (C&R) outages. Placement on the worst performing circuits is driven by the number of customer outages over the past three years.[20] NorthStar reviewed the lists for the six year period from 2007 through 2012.
  - None of the circuits on the C&R list repeated in a subsequent year after its initial placement on the list. In total there were 180 circuits rotating through this list.
  - Only four out of 190 circuits on the vegetation list repeated in a subsequent year after initial placement on the list.[21]

- LIPA has installed over 1,200 automatic switching units (ASUs)[22] and ten manual switches to improve circuits and overall system reliability.

[20] DR 741
[21] DR 122
[22] The purpose of ASUs is to transfer automatically to other circuits when a disturbance is found on a circuit.

9.3.6 LIPA reported in its 2010-2020 Electric Resource Plan that over $3 billion was invested in the T&D and generation systems since 1998 to improve reliability. However, LIPA is unable to verify system improvements through capital project records.

- LIPA reported system improvements in the following areas.
  - Substation and transmission projects, accounting for almost $900 million in upgrades and equipment replacements;
  - Distribution additions and upgrades, totaling approximately $1.3 billion;
  - Generation and new resource interconnections, totaling approximately $300 million;
  - Fifteen new substations, constructed on new sites;
  - Over 200 miles of new transmission line installations, over half underground;
  - Enhancing LIPA interconnections through merchant contracts: Cross Sound Cable to Connecticut and the Neptune Cable to New Jersey; and
  - Implementing one of the first Storm Hardening programs in the U.S. in 2006, representing a $500 million, 20-year program to reduce the impact of major storms (e.g., hurricanes).[23]

- LIPA was unable to provide verification of these system improvements through capital project records.[24]

9.3.7 The system planning function identifies system needs for major projects, develops project scopes, and justifies projects for reliability and customer impact. However, system planning fails to develop its primary work product – a consolidated capital investment roadmap that optimizes investment in the T&D system.

- Extensive study and system analyses identify projects for identification of infrastructure needs, specification of operating criteria, and support of the NYISO.

- A formal Transmission System Plan is submitted to the NYISO on an annual basis identifying ten years of expansion plans associated with the FERC 715 filing. The 2013 capital budget identifies transmission projects through 2018 and a long term plan for the future of the transmission system.[25]

- NorthStar's analysis of recurring system planning studies shows that they are numerous, generally effective in identifying system needs and are normally conducted in a timely manner. **Exhibit 9-6** provides an overview of the studies/analyses that are conducted, the frequency, verification of timeliness, and NorthStar's assessment of whether the study fulfills its stated objectives.[26]

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[23] DR 59, page 49
[24] DR 535 - Unanswered
[25] DRs 206 and 543
[26] DR 63 and DRs 536 through 565

9.3.8 System planning studies and analyses are comprehensive.

- Planning studies as described in **Exhibit 9-6** are a major contributor to the planning process. Over 30 planning studies/products/analyses contribute to the system planning process.[27] The planning products cover a wide variety subject matter across LIPA's system, including:

  - NYISO transmission studies
  - Load pocket studies
  - Long term transmission plans
  - Distribution feeder studies
  - System efficiency
  - System contingency analysis
  - T&D operations

- New business, identified as load growth, is found in the load forecasts. The load forecasts are inputs to the planning studies.

- The system plan includes T&D system reliability projects and new business projects.[28]

9.3.9 The long-term system planning function addresses land availability, right-of-way, land use and environmental siting constraints.

- A lump sum budget for land acquisition increases in the budget 2 percent each year. It appears in LIPA's budget as separate item under General and Miscellaneous Capital.[29]

- Project specific land acquisition, such as the "EGC" project, is also shown in General and Miscellaneous Capital.

- Property purchase price and space limitations in facilities are discussed in the project justification documents (PJDs).[30]

- Property costs studies for the routing of new lines and construction of new substations are discussed in some PJDs.[31]

- The conceptual budget detail for individual projects allows for the inclusion of environment engineering. NorthStar found estimates for environmental engineering on new substations and coastline cable replacements.[32]

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[27] DR 63
[28] DR 206
[29] DR 206
[30] DR 560, 561, 581
[31] DR 560
[32] DR 206

Exhibit 9-6
Planning Studies and Analyses

Study or Work Product Title/ Nominal Frequency	Objective	Assessment
Summer Peak Load Forecast (20 Years) Annually, Fall	Develop peak load forecast for NYISO installed capacity requirements, other regulatory filings and Resource Planning Coordinating Committee	The study is current. The LIPA Load Forecast provides the data for peak load.
Forecasted Load Duration Curves under Normal and Extreme Weather (3 years) Annually, Spring	Develop for Summer Operating study	LIPA provided Load Duration Curves for normal and extreme weather. Data is used for three years.
NYISO Operating Study Annually, Spring	Identify power transfer limits expected in the New York Control Area during upcoming peak summer season.	The study is current. LIPA participated in this process with the NYISO. LIPA is responsible for supporting the NYISO in its assessment of Zone K. Zone K is the entirety of Long Island.
NYISO Winter Operating Study Annually, Fall	Identify power transfer limits expected in the NYCA during upcoming winter peak season	The study is current. LIPA participated in this process with the NYISO. The report is publicly available on the NYISO website.
LIPA Summer Operating Study (minus extreme contingency and voltage assessment analysis) Annually, Spring	Identify T&D system limitations and power import limits expected during upcoming summer peak season (It also includes extreme contingency analysis)	The study is current and fulfills the stated objectives.
LIPA Winter Operating Study Annually if required	Identify T&D system limitations (due to maintenance and scheduled outages) and power import limits expected during upcoming winter peak season	The study is current and fulfills the stated objectives.
Extreme Contingency Conditions Analysis Annually, Spring	Analyze transmission system performance during extreme contingencies (Included in Summer Operating Study)	The study is current and fulfills the stated objectives.
Long Term Plan (LTP) Bi-Annually, Fall	Transmission owners provide details of their long term transmission plans including criteria, models, and local area development	The study is not current. LIPA provided its 2011 Plan and due to be re-published in 2013.
Short Range (Up to 5 Years) Transmission System Studies When generation additions are identified and/or when load growth demand substation reinforcements in an area of the system	Identify transmission system limitations and recommend reinforcements for an area of the system within a 5-year time frame. Results in development of major Transmission capital projects	The study is current, LIPA provided the 2011 Study. The study fulfills the stated objectives.

Study or Work Product Title/ Nominal Frequency	Objective	Assessment
Long Range (5 to 40 Years) Transmission System Study Every five years or when generation additions are identified and/or when load growth demand substation reinforcements in an area of the system	Identify transmission system architecture in the 35 to 40 year range and identify transmission system limitations and recommend reinforcements that will be required in 5 to 20 years to meet load growth and new generation injections	The most recent study (December 2007) requires an update.-Various components were updated and used for the 2500MW generation RFP in 2010.
System Reliability Impact Studies As required for new generation or interconnection additions	Determine impact on the LIPA transmission system of proposed new generation or interconnections and recommend reinforcements to the system as required. Could result in development of major Transmission Capital Projects	The NYISO coordinates the process and most recently required a study in 2010 for the NNC cable upgrade. LIPA provided the study in December 2010.
Short Circuit Study Transmission Breakers Every 3-5 years and when studying generation additions and/or major modifications to the transmission system	Ensure that there are no overstressed circuit breakers (Provided in Summer Operating Study)	The study is current and fulfills the stated objectives
Angular Stability Study Every 5 years and when studying generation additions and/or major modifications to the transmission system.	Ensure that electric system will meet system stability design criteria.	The study (February 2, 2011) is current and fulfills the stated objectives
Voltage Recovery Evaluation - impact of load type changes Every 2 years	Verify validity of complex motor modeling (Included in Summer Operating Study)	The study (June 2012) is current and fulfills the stated objectives
System Voltage Study Substation voltages will be analyzed as part of each transmission system study	Ensure system voltage design criteria is met	This is an analysis of voltage levels. The work product is current and LIPA provided a presentation based on an analysis
NYPA Customer Deliverability Study Annual. Every March (The study is a contractual requirement with the NYPA))	Assess deliverability of capacity to NYPA customers on Long Island	The study is current (February 2013) and fulfills the stated objectives
LIPA Electric System Loss Study Annual update and periodic major update on need basis	Determine the LIPA system energy (MWHR) and demand (MW) losses by operating season for T&D delivery components	The study is current and fulfills the stated objectives

Study or Work Product Title/ Nominal Frequency	Objective	Assessment
System Reactive Reserves Evaluation Annually	Provide 10 Year system reactive load forecast and evaluate reactive reserve needs on T&D system	The study is current and fulfills the stated objectives
Summer Load Forecast Distribution Substations and Circuits Annually, Spring	Develop three (3) Year Summer Peak Load Forecasts for all LIPA and other major customer-owned distribution substations and circuits.	The work product is current. It is 3 year forecast of circuit and station loads. The work product meets the stated objectives.
Winter Load Forecast Distribution Substations and Circuits Annually, Fall	Develop 3 Year Winter Peak Load Forecasts for all LIPA and other major customer-owned distribution substations and circuits	The work product is not current. It is a 3 year forecast of circuit and station loads. Fulfills the stated objectives except it has not been developed for 2012.
Distribution Load Transfers Semi-Annual - Spring and Fall	Develop distribution load transfers for seasonal operation of distribution system and for the rearrangement of the distribution system based upon planned distribution line projects.	The work product is current. It represents operational instruction for a number of situations. It fulfills the stated objectives.
Substation LTE/STE Overload Analysis Annually, Spring	Develop contingency load shed plans for substations where forecasted load will exceed emergency ratings of remaining energized substation transformers.	The work product is current. It represents operational instruction for a number of situations. It fulfills the stated objectives.
Seasonal Bus -Tie Operation Studies Semi-Annual - Spring and Fall (Included in Substation LTE/STE Overload Analysis)	Analysis of whether distribution bus-tie breakers should be operated in Normally Open or Normally Closed position during Summer and Winter load periods	The work product is current. It represents operational instruction for a number of situations. It fulfills the stated objectives.
First Contingency Study of Substations / Circuits Annually, Spring	Study of contingency capability of all distribution substations and circuits to provide assistance / instructions to Operating Depts. during emergency operation of the distribution system for peak summer load periods.	The work product is current. It represents an analysis of system load and provides operational instruction for a number of situations. It fulfills the stated objectives
Distribution System Area Studies Annually	Study of a Service Area to identify distribution system (substation/circuit) reinforcements required to supply forecast load growth. Results in the development of major substation capital projects and distribution line projects	Two recent work products were provided. The documents represent project analysis and justification.

Study or Work Product Title/ Nominal Frequency	Objective	Assessment
Distribution Line Programs: **1. Conversion & Reinforcement (C&R)** **2. New Substation Exit Cable** **3. Capacitors** **4. Automatic Sectionalizing Units (ASU)** **5. Short Circuit Distribution Breaker Assessment** Annual - Early Spring through Late Winter	Develop projects to ensure adequacy of the distribution system to normally supply forecasted load on circuits and substations, to provide capacity during emergency conditions, to provide operational flexibility to transfer load, and to provide a high degree of service reliability to the customer	The work product is not current, a 2011 document was provided. This work product is a list of projects and project justifications.
Voltage Control Analysis Semi-Annually – Spring and Fall	Review forecasted Summer and Winter distribution circuit conditions and determine maximum allowable voltage reduction permitted on each circuit during Peak Load periods or during system emergencies	The work product is current. The work product represents lists of transformer banks and the appropriate voltage control settings.
Resource Needs Analysis Study Annual	Resource Needs Assessment supporting the NYISO.	The study is current and fulfills the stated objectives.
FERC 715 Submission Annual April submission to FERC	Annual requirement for submitting transmission system data and planning criteria to NYISO and FERC	The study is current. LIPA participated in this process with the NYISO.
IR-3 Gas Burn Local Reliability Rule Annual Review to determine need to update	Determine limitation on Northport gas burn requirement	The study is current and fulfills the stated objectives.
NYSRC Initiatives (e.g. Integrated Resource Management study) Annually	Provide support analysis to the NYISO.	The study is current and fulfills the stated objectives
NYISO Annual Transmission Baseline Assessment (ATBA) Annually - February	Create a baseline transmission system for meeting reliability needs of transmission district. This configuration is used for cost allocation purposes of generation and merchant transmission interconnection per NYISO OATT Attachment S procedures.	The study is current. LIPA participated in this process with the NYISO.
Review and Update of LIPA T&D Criteria Document Every two years	Ensure the document reflects the latest changes to LIPA's T&D Planning Criteria and Guidelines.	The work product is not current. The September 20, 2010 work product is still used.

Source: DR 63, DRs 536 through 566, 791 and 792

9.3.10 The planning function seldom includes public interaction on specific projects.

- The PJDs reviewed did not examine neighborhood impacts, potential public conflicts, and the need for community education and involvement. [33]

- NorthStar found some notices on the internet of public hearings concerning specific projects.[34]

- LIPA's website provides some links to project specific information, pubic notices, and a schedule of events.[35]

9.3.11 Capital projects are prioritized using an objective risk scoring methodology.

- Capital projects are initiated via several means.

  - The Network Strategy Planning group uses analytical processes, systems, conducts load flows and forecasts to determine system reinforcement/addition requirements.
  - The Reliability Management group captures and studies system failures and performance to determine reliability enhancement requirements.
  - Electric Operations personnel have knowledge of system "trouble spots" and may also recommend projects for system reliability and/or improvement.

- National Grid assigns each discretionary T&D capital project a risk score to provide guidance in the selection and prioritization of projects and programs in the capital budget. Risk scores are developed in conjunction with the creation of PJDs between March 15 and June 30 of each year. Project risk scores are then reviewed by LIPA in July and August.

- The risk score is based on a combination of potential project impact and likelihood.

  - Project impact is comprised of four categories, which include regulatory requirements, customer service requirements, financial performance, and technical performance. For each category, a project is assigned a score ranging from 1 to 10. Scoring is completed by responding to a series of questions about the project, which are listed by category and found in individual scoring tables.
  - Likelihood refers to the risks associated with an equipment failure or malfunction event. This category considers the timeframe in which the event can occur, the likelihood of the event occurring, and how readily the event could be detected. The overall likelihood score is calculated by multiplying the project's scores in the exposure, probability, and detection categories.

- The overall risk score of the project is calculated by multiplying the highest individual impact score for all categories (regulatory requirements, customer service

[33] DRs 560 and 581
[34] http://www.lipower.org/pdfs/company/projects/SHBH/010708_SHBHPB.pdf
[35] http://www.lipower.org/company/powering/

requirements, technical performance, and financial performance) and the likelihood of that particular impact occurring. In general, only a single likelihood needs to be considered, unless the impact scores are close and associated with different likelihood scores. If a project scores high in multiple categories, consideration is given for multiple benefits in the scoring. The ranking matrix is illustrated in **Exhibit 9-7**.

Exhibit 9-7
Risk Scoring Impact-Likelihood Matrix

IMPACT										
10	10	20	30	40	50	60	70	80	90	100
9	9	18	27	36	45	54	63	72	81	90
8	8	16	24	32	40	48	56	64	72	80
7	7	14	21	28	35	42	49	56	63	70
6	6	12	18	24	30	36	42	48	54	60
5	5	10	15	20	25	30	35	40	45	50
4	4	8	12	16	20	24	28	32	36	40
3	3	6	9	12	15	18	21	24	27	30
2	2	4	6	8	10	12	14	16	18	20
1	1	2	3	4	5	6	7	8	9	10
	1	2	3	4	5	6	7	8	9	10

Likelihood

- Risk scores are reviewed to determine which projects will be included in the yearly budget submittal, and therefore are a major factor in project prioritization.

- The goal of T&D project prioritization is to identify projects that create the most value for LIPA relative to those projects that create less value. Projects are ranked on a funding curve prioritized by their risk score (highest to lowest), with breakpoints at funding limits. Projects falling within the same risk score are reviewed again to verify that they have relatively the same importance and benefit.

- The prioritization is used as a guideline for developing the first list of selected projects. National Grid then reviews the selected projects to ensure there is adequate work to support the in-house and anticipated contracted labor forces.[36] A final list of projects is determined jointly between LIPA and National Grid.

- The Program Management organization schedules meetings with project participants (planning, engineering and construction) to discuss projects they are proposing for consideration. Project costs are developed by these functional areas based on past experience and include opinions of material and work hour estimates.[37]

[36] On-island contracted labor has been found to be important to support storm restoration efforts.
[37] DR 79 – Budget Process

9.3.12 LIPA does not analyze reliability benefits for customers in the context of short and long-term rate effects.

- Project justification descriptions for large, complex projects provide detailed and in some cases alternative analyses, where reliability and engineering feasibility are considerations. [38]

- The risk scoring methodology allows comparisons of competing projects based on the relative risk associated with each project. Project cost is not a consideration in the risk analysis.

- LIPA does not perform economic benefit/cost analyses for capital project justification and the resulting rate impacts versus improved reliability are not analyzed. National Grid does perform economic analysis of alternatives on some major capital projects.

9.3.13 LIPA has appropriate priorities, guidance and other instructions for engineering evaluations, reliability improvements, tradeoffs and decision-making.

- LIPA has developed numerous planning processes and work products that focus on asset management, aging T&D system, inspection, testing programs and their integration with system reliability issues.[39] These include:

  - Asset management oversight is performed by the Long Island T&D Asset Management Steering Group (AMSG). AMSG is comprised of LIPA and National Grid senior management and meets monthly. AMSG has a formal charter and is responsible for the strategic asset management planning.
  - Circuit Improvement Program (CIP) Inspection provides a field inspection (selected worst performing circuits) of all primary distribution facilities with special emphasis on three phase main (which is patrolled by foot). In 2012, a supplemental acoustic based inspection (Exacter) is also performed for each CIP circuit (acoustic can detect some defects that can't be seen visually).
  - Primary Voltage Cable Diagnostics includes tan delta test to determine overall health of the cable insulation and partial discharge which determines if there are local defects especially in the splices or joints.
  - Infrared Scans of Overhead Distribution Lines involves the use of an infrared camera to examine line clamps, taps, splices, and equipment along the three-phase mainline for possible overheating, in order to replace a component or splice before failure causes an outage. Repairs to identified hot spots are prioritized based on the severity of the overheating. Fifty percent of overhead distribution lines are targeted to be scanned annually.
  - Infrared Scans of Overhead Transmission Lines involves the use of an infrared camera to examine line clamps, taps, splices, and equipment along transmission lines for possible overheating, in order to replace a component or splice before failure causes an outage. Repairs to identified hot spots are prioritized based on

[38] DRs 560 and 581
[39] DR 60

the severity of the overheating. One hundred percent of overhead transmission lines are targeted to be scanned annually.

- Wood Pole Inspection, Replacement and Reinforcement program is geared at maintaining the structural integrity of the pole infrastructure by conducting ground line inspections of wood distribution poles for evidence of decay, shell rot, insect infestation or other damage to ensure they meet required strength criteria. Inspection determines poles in immediate danger of failure as well as those that need reinforcement or replacement in the near future. **Exhibit 9-8** provides details on the wood pole program requirements and performance.

Exhibit 9-8
Wood Pole Program Performance

System	Program Requirement	Performance
Transmission		
Inspection	Every 11 years Complete in 2012	2011 - 15 % complete 2012 - 100 % complete on 9/30/2012
Replacement	Insufficient strength 396 poles identified	2012 – no replacements (Sandy) 2013 – 167 planned, 33 complete to date 229 scheduled for 2014 and 2015
Distribution		
Inspection	Every 11 years	2012 and 2013 – 2.9% complete (Sandy) Program resumed again on May 24, 2013
Replacement	Replace or reinforce 171 poles (to date) identified	2012 – no replacements[40] 2013 to 2015 – 171 poles scheduled, 14 completed to date

Source: DRs 845 through 848

- Emergency Restoration Procedure - Field Inspection survey of overhead distribution as part of system wide training exercise. Hazardous conditions or major nonstandard conditions are identified and forwarded to the appropriate organization for corrective measures.
- Reliability Centered Maintenance (RCM) methods were developed to determine intervals for preventive maintenance tasks for specific substation component types such as transformers/regulators, circuit breakers, pump houses, load tap changers (LTCs), network protectors and transformers and the DC battery system. The method begins by establishing a preliminary task interval based on statistical or historical trending analysis utilizing failure data or experience maintenance interval data.
- Monthly condition assessment based on observed characteristics of all equipment in the substation yard. During the inspection cyclometer readings are taken for breakers and transformer bank LTCs. Also, the transformer bank oil temperature is recorded during this process. The cyclometer readings are used to calculate the number of operations since the equipment was last overhaul or test. This information is used to support of RCM processes and substation maintenance efforts to improve reliability.

[40] 4,600 poles were replaced as a result of Hurricane Sandy and an additional 1,000 were replaced due to other inspection programs (DR 845)

- Transformer Dissolved Gas Analysis (DGA) testing is done on all substation transformer banks on a yearly basis. The by-products are characteristic of the type of incipient fault condition and used to determine maintenance and overhaul cycles.
- Significant System Event Investigation (SSEI) - General Operations Procedure (GOP) 10423 establishes a method to initiate a SSEI in response to significant disturbances, events and failures on the T&D system. The GOP also establishes the departmental roles and responsibilities for the SSEI.
- Overhead transmission - the major RCM components are tree trimming, thermovision, annual walk downs and acoustic inspections. Inspections include hot spot inspections, leaf on/leaf off clearance patrols, and walk-ride inspections that are performed annually. In addition, emergency/special patrols are performed as necessary following a trip or on an as needed basis to identify specific problems or reliability related issues. Findings are maintained in an Open-Item Database.

9.3.14 The processes and criteria for making decisions regarding replace vs. repair, including how the overall construction program planning process is affected, are not documented.

- LIPA does not have formal written procedures that govern replace or repair decisions. As part of the PJD process, National Grid includes alternatives analysis and the justification of a project based upon its perceived system need and risk analysis. Based on NorthStar's review of PJDs, economic payback is not considered and project cost estimates are not provided.[41]

- For other program based repair versus replacement decisions, project decisions are based on observed field conditions and/or the availability of replacement parts.

9.3.15 National Grid and LIPA generally do not perform economic benefit/cost analyses for capital project justification. T&D capital projects are selected, and approved using conceptual annual spend estimates. Refined project cost estimates are used to meet LIPA annual spending levels.

- Project estimates are developed using conceptual scope and submitted to LIPA along with PJDs by the end of June each year. These conceptual estimates are referred to as "C" estimates. Meetings are held between National Grid and LIPA to review projects submitted. Approved projects are submitted to the LIPA Board for budget approval in October.[42]

- The total conceptual estimate of a project is not part of the decision making process. Utilizing annual conceptual estimates, the cost of a project or its value is not evaluated in any economic analyses.

[41] DR 68, 188 and 581
[42] DR 79 – Budget Process

- As project engineering is performed, budget level estimates (referred to as "B" estimates) are developed. These estimates are either greater or less than the conceptual estimates and projects will be added to the work plan or deferred to meet LIPA's approved budget level at C-to-B meetings. C-to-B meetings are chaired by National Grid's Program Management organization to get general agreement on expected project costs. When budget level estimates are considered, Network Strategy Planning makes recommendations on projects to be added or deferred in order to meet LIPA's approved spending level. Program Management reviews the work plan and resource utilization. The results of this process are submitted to LIPA for approval.

- Budget level estimates are developed during the project execution, after projects have been approved, and are used to stay within LIPA spending limits.

9.3.16 LIPA/National Grid develops accurate system forecasts which are used in identifying infrastructure requirements.

- LIPA/National Grid develops annual coincident peak demand forecasts. The forecast is developed for normal weather and extreme weather conditions. NorthStar reviewed the normal weather forecast against the actual weather normalized peaks and found the model to operate accurately. (See Chapter 17 – Long-Term Energy Supply Planning for additional discussion of the load forecasting process.)

- Load Forecasting provides extreme weather coincident peak demand forecasts to T&D planning. The forecasts have a variety of confidence levels including 50/50 and 95/5 confidence levels. Transmission planning utilizes the 95/5 and 50/50 confidence level forecast for its extreme conditions voltage and thermal assessments (Summer Operating Study) and the 50/50 confidence level for its support of the NYISO Summer Operating Study.[43]

- Forecasting annually provides load data, weather-normalization results and methodologies and peak load forecasting results and methodologies as prescribed in the NYISO Services Tariff Sections 5.10 and 5.11 to support:

  - The calculation of the NYCA Unforced Capacity Requirements.
  - The load forecasts used in the Comprehensive Reliability Planning Process (CRPP).
  - The NYISO's load data submission filings to NPCC, NERC, FERC, and other reliability and regulatory bodies.

- Utilizing the load forecasts:[44]

  - National Grid's System Planning organization conducts summer operating studies annually to identify T&D system limitations and power import limits expected during upcoming summer peak season.

[43] DR 538 and DR 540
[44] DR 61

- Annual and monthly forecasts of system load are provided to the NYISO. The annual load forecast data that LIPA provides is combined with similar data provided by the other load serving entities on Long Island to form the LI Transmission District Load Forecast.
- Load forecasts are adjusted to track both short and long term changes to peak load requirements and resource needs. Examples of internal data include system peak forecast estimates, demand side management programs, retail access programs, contract supply and resource purchase data. Some examples of data collected and used from external sources include NYISO Installed Reserve Margin & Locational Requirements, Unforced Capacity (UCAP) and Capacity Resource Interconnection Service (CRIS) ratings for generation, retail access load forecasts from participating ESCO's and market based information regarding overall level of resource availability.

- Load forecasts, resources, and distribution loads are integrated and reconciled periodically.

  - Distribution planning develops load forecasts for each of its 1,107 feeders. The load forecast is based on the historical peak demand of each feeder. Every year the actual demand, the forecast demand, and the capability of the feeder is reviewed.[45]
  - Transmission planning utilizes the extreme weather coincident peak demand forecast for its planning efforts. These forecasts are inputs into the transmission planning studies. Reconciliation occurs in the evaluation of how well the normal weather coincident peak demand forecast performed against actual weather normalized peak demand.

- Other load and infrastructure factors such as advanced metering and energy efficiency initiatives are given consideration in the planning process. Energy efficiency and other initiatives are forecast as reductions to energy and coincident peak demand requirements.

9.3.17 Storm hardening, an element of system planning, is in place to minimize the potential effects of major storms.

- In 2006, a storm hardening policy to address the threat of severe storms, including hurricanes, was adopted. This long-term program is anticipated to cost up to $500 million over 20 years to improve the capability of the electric system on Long Island to withstand the impacts of hurricanes and other severe storms, and to shorten the time required to restore service to customers when outages occur due to storms. The storm hardening plan includes:[46]

  - Specific programs/projects to address critical infrastructure
  - Specific projects to address flood prone/surge areas

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[45] DR 694
[46] DR 60

- Incremental spending on system reinforcement projects to increase strength of infrastructure
  - Reinforced foundations to support critical equipment and structures
  - More robust steel infrastructure
  - Stouter poles
  - Address site specific flooding issues
- Enhanced right of way maintenance
  - Removal of danger trees adjacent to lines
  - Accelerated tree trim cycles in areas
  - Exceed annual tree trim mile commitment for both distribution and transmission programs
  - Expand transmission right of ways to provide additional clearance
- Installation of new underground circuits
- Replacement of deteriorated poles
- Protection for substations from flooding and storm surges
- Reinforcement of substation foundations and structures to withstand higher wind speeds
- Increase in strength of selected transmission pole lines to withstand higher wind speeds and storm related flooding along Long Island Railroad (LIRR) corridors and at major road crossings
- Increase in strength of selected distribution pole lines to withstand higher wind speeds
- Increased tree trimming clearance and removal of hazardous trees/limbs outside clearance zones

9.3 Recommendations

9.4.1 Develop a minimum five-year consolidated system plan – an investment model optimizing capital investment in the LIPA transmission and distribution system. The plan should include the elements listed in **Exhibit 9-9** on the next page:

9.4.2 To the extent practical, the system planning function should justify capital improvement projects based on cost/benefit analysis in addition to engineering needs analysis.

- Cost/benefit analysis (CBA) is often used to evaluate the desirability of a given project. It is an analysis of the expected balance of benefits (e.g., reliability) and costs (e.g., rate impacts), including an account of foregone alternatives and the status quo.

- CBA helps predict whether the benefits of a project outweigh its costs, and by how much relative to other project alternatives (e.g., alternative projects can be ranked in terms of the cost/benefit ratio in addition to risk scoring).

Exhibit 9-9
Elements of a Long Term Transmission Plan

Executive Summary
Goals and objectives of the plan Planning horizon Contributing data sources Discussion of the service territory including long term needs and external pressures Planning Approach - drivers (load forecasts, generation locations) and models Future system layouts
Planning Factors
Planning Considerations Expansion Drivers Customer Needs Planning Criteria Methodology and Assumptions Prioritization Northeast Reliability Council (NERC) Compliance
Studies
Introduction to Study Methodology System Wide Analyses Asset health assessments Zonal and regional analyses Alternative Analyses
Projects
Assessment of planned versus completed projects New in Current Year Under construction Approved Pending T-D Connections Customer Projects Generation Interconnections
Routing and Siting
Public Outreach Siting Process New Right of Way Existing Right of Way

10. CAPITAL PROGRAM AND PROJECT PLANNING AND MANAGEMENT

This chapter covers capital program and project planning and management to preserve assets and expand the system.

10.1 Background

Program and project planning and management are of importance to executive management and regulators for many reasons, including:

- The potential adverse effects of poor project cost and schedule;
- The possibility of management being poorly informed and caught off guard regarding project issues and events;
- Problems arising from technical and managerial limitations or insufficient staff resources for successful project completion;
- Pressure from the public or politics relative to project selection;
- The "hidden" cost of delays on customers who must forgo the benefits of late projects; and
- The risks arising in general from a potentially litigious environment.

Early program and project planning includes the decisions and processes that shape a project and determine its success. Performing adequate analyses, establishing initial project work plans, and considering various risk factors are critical for successful project execution. Project risks and the process for prioritizing projects must be assessed to develop plans for financing and to identify potential resource requirements and limitations.

Capital projects are investments in the LIPA electric system to preserve assets, ensure or improve system reliability and safety, protect the environment, or expand operating efficiency or capacity. Project scope, cost, and schedule estimates provide the foundation for monitoring and controlling capital projects. While uncertainty is involved in any project estimate, identification of known requirements, particular areas of uncertainty, risk and complexity is fundamental to demonstrating feasibility, analysis of alternatives, and demonstration of project benefits.

The full implication of many project management decisions cannot be known until project completion. The review of program and project management capabilities must therefore focus on the management decision-making processes used to control construction costs, schedules and quality – as evidenced, for example, by organization and control mechanisms used and whether they are sound, adhered to, logical, and responsive to changing conditions. Key to an audit of project management is the identification of controllable and non-controllable aspects of capital improvement projects. Through this differentiation, those topic areas in which management can reasonably be expected to plan, organize, direct and control activities are identified. These are the aspects of engineering and construction management that warrant detailed analysis and explanation. Non-controllable aspects are those driven by externally imposed changes and/or natural acts which cannot be foreseen and for which management action is necessarily reactive. Additionally, independent and objective analysis of project management performance requires the development of both qualitative and quantitative material focusing on both project specific and industry facts. This integration is basic to achieving a complete understanding of the importance of management decisions and the magnitude of their effect. The underlying premise of project management is the early identification of issues that could affect the overall success of the project and the direction of appropriate management intervention.

Fortunately, there is a robust body of knowledge defining "generally recognized good practices" in portfolio, program, and project management. Among them are the following:

- 2007 Comparison of Construction Management and Program Management Costs, Construction Management Association of America
- Best Practices Procurement Manual, Federal Transit Administration (FTA), November 2001
- Business Process Change: A Guide for Business Managers & BPM (Business Process Management) & Six Sigma Professionals, 2nd Edition, 2007
- Construction Management Standards of Practice -- 2010 Edition; Construction Management Association of America (CMAA)
- Government Design-Bid-Build Work Breakdown Structure (WBS), Project Management Institute
- Guide to the Project Management Body of Knowledge (PMBOK® Guide), 4th Edition, Project Management Institute
- Organizational Project Management Maturity Model – 2nd Edition, Project Management Institute (PMI)
- Publically Available Specification (PAS) 55: 2008 Specification for the Optimized Management of Physical Assets Parts 1 and 2, by the British Standards Institution
- Standard for Program Management, 2nd Edition, Project Management Institute

The LIPA management audit compared available written procedures (stated LIPA and National Grid practices), to actual practice as observed in the field and documented in audits of representative projects, and to good practices recommended by standard-setting organizations.

10.2 Evaluative Criteria

- Are the program and project planning, design, estimating, engineering, costing, scheduling and execution functions well documented and performed to LIPA and recognized standards for good practice?
- Are materials and equipment, transportation and other logistical support planned and managed effectively for programs and projects?
- Does LIPA analyze trade-offs and make decisions in order to optimize the use of in-house workforce versus contractor labor?
- Are contractor and engineering bidding practices appropriate?
- Are construction contractor projects planned and managed effectively?

- Does LIPA have effective quality assurance and quality control at the program and project level?
- Does LIPA have effective contractor management and project/program management, including accountability, goals, objectives, and performance measurement?
- Does LIPA use a baseline scope, budget, and schedule for monitoring and controlling projects?
- How well have projects, programs, and portfolios performed? Are these results visible in a timely way for monitoring and controlling?
- Does LIPA utilize a well-defined structure to estimate, track and monitor project performance and is it used consistently?
- Are project estimates accurate and updated on a periodic basis?
- Is monitoring and controlling against project baselines for scope, budget, and schedule performed?
- Are project scope changes effectively controlled and communicated among participants?
- Are project change orders managed and controlled effectively?
- Are project quality control and technical requirements effectively communicated and transferred to contractors?

10.3 Findings and Conclusions

10.3.1 LIPA's Management Services Agreement (MSA) assigns responsibility for capital program and project planning and management to National Grid but does not provide incentives for effective project management.

- The MSA defines capital improvement projects as repairs and replacements of the T&D system that do not constitute routine maintenance, along with system expansion. These capital improvements are the responsibility of the "Manager" (National Grid), to be performed pursuant with the consent of LIPA. LIPA has the right, when the Manager has materially exceeded the capital plan and budget to require the Manager to defer specific capital improvements for the remainder of the year.[1]

- The Manager only has to use its "best efforts" to limit the costs incurred in making each capital improvement consistent with prudent utility practice.

- LIPA may object to any capital cost on the grounds that the capital cost or the amount being charged to LIPA was improperly computed, costs incurred were unreasonable or work was delayed due to circumstances for which the Manager was responsible.[2]

- Dispute resolution, mediation and reconciliation terms and rights are defined under the MSA.[3] If LIPA disputes any amount billed by the Manager in any billing statement, LIPA must pay undisputed amounts and give written notice to the Manager

[1] DR 4, MSA Article V, Section 5.1
[2] DR 4 – Section 6.10: Disputes
[3] DR 4, MSA Section 6.10.B

indicating the portion of the billed amount that is being disputed and providing a summary statement of its objections. Following written notice, LIPA must give the Manager a written statement providing all reasons then known to LIPA for its objection to or disagreement with such amount.

10.3.2 National Grid's provision of project management and capital improvement program information has not satisfied contract requirements in all cases.

- The MSA assigns development of the T&D capital plan and budget to National Grid. National Grid prepares a proposed annual, two-year and five-year capital plan and budget for capital improvement projects which is to include:[4]

    1. Proposed capital improvement by function (e.g., transmission, substation, distribution, communication, common plan, and public works) and project location.
    2. Detailed project descriptions.
    3. Planned initiation date and expected duration of each project.
    4. An estimate of the amount of the capital cost for each project (separately specifying the engineering, material, contract and labor costs), including the dollar amount of capital expenditures per year if the project requires more than a year to complete.
    5. An explanation of the relationship to other planned or subsequently required capital improvements or additions.
    6. The anticipated useful life of each capital improvement or addition.
    7. The economic and engineering justifications for each capital improvement or addition, including where applicable, quantification of system performance changes, expected effect, and the ability to meet any related performance metrics.
    8. An indication of whether the capital improvement or addition is planned for performance by the Manager work force or by third party contractor.

- Approximately half of LIPA's capital improvements are ongoing programs (e.g., pole replacements, circuit improvements, transformer and capacitor replacements, etc.) that are budgeted in lump sum amounts and are not addressed on a project-specific level.

- For specific capital improvement projects reviewed, not all information required by the MSA is provided. Specifically:

    - Planned initiation date and duration are not provided on Project Justification Documents (PJDs) as called for by item 3, above.[5]
    - Projects have only a conceptual estimate for the annual period anticipated, and only when it has been approved for the upcoming budget year does it receive any greater level of detailed information as called for by item 4, above.[6]

[4] DR 4, Article V, Section 5.2
[5] DR 188 and 581
[6] DR 79, 188 and 206

- The anticipated or useful life of equipment is not included in PJDs as called for in item 6, above.[7]
- Project engineering justifications are provided but not economic justifications as called for in item 7.
- Projects to be contracted versus performed by National Grid are determined by National Grid when developing work plans, not as part of the PJDs as called for by item 8, above.[8]

- The MSA requires that other than for emergency repairs or replacements, including storm events, the Manager shall prepare at LIPA's request, a repair-or-replace analysis for replacements of the T&D system costing more than $500,000. Based on a review of capital projects proposed, LIPA did not request nor did National Grid prepare replace versus repair analyses in PJD documents.[9]

- The MSA requires that National Grid's capital plan and budget submission include explanation and justification of costs in a form acceptable to LIPA. The proposed capital projects include conceptual project cost estimates, a single numeric amount, but do not include cost justification.

10.3.3 Under the MSA, the effectiveness of program and project planning and management is not directly addressed. In the absence of specific contractual obligations to provide effective program and project management, responsibility for results falls to LIPA.

- Under the MSA, National Grid only agreed to use its "best efforts" to limit the costs incurred in making each capital improvement consistent with prudent utility practice.

- LIPA may object to any capital cost on the grounds that the capital cost or the amount being charged to LIPA was improperly computed, costs incurred were unreasonable or work was delayed due to circumstances for which National Grid was responsible.[10]

- LIPA must take the initiative to identify errors or determine unreasonable costs.

10.3.4 LIPA's program and project management oversight of National Grid has been minimal and ineffective.

- LIPA's organizational resources for T&D operations, capital improvement program and project management oversight consist of three resources within the four-member T&D Operations organizational unit shown in **Exhibit 10-1**: the T&D Vice President, Director of T&D Planning, and a Senior Engineer position (currently vacant).[11]

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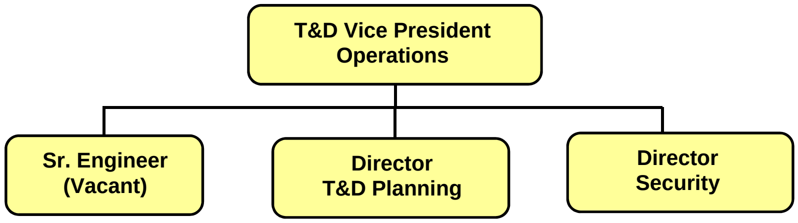
[7] DR 581
[8] DR 87 and 88
[9] DR 184, 560 and 581
[10] DR 4, MSA Article V, Section 5
[11] DR 1, LIPA organization charts – March 2012 and fact verification.

Exhibit 10-1
LIPA T&D Oversight Organization



- The roles, responsibilities, mission and functions relative to LIPA's oversight of T&D program and project management have not been formalized or expectations communicated to National Grid. Furthermore, LIPA's ability to modify National Grid's managerial processes other than identifying, quantifying and objecting to inaccurate or unreasonable costs is not covered within the MSA.

- There have been few capital project audits and documented results of these audits are unavailable, indicating an unwillingness to challenge the reasonableness of National Grid charges as provided in the MSA.[12]

- Section 4.16(E) of the Amended and Restated MSA recognizes that performance audits may be performed "from time to time." LIPA could provide only one audit of capital projects since 2008.[13] Highlights of that audit are as follows:

- The audit was performed by Navigant Consulting in 2009 covering capital projects performed in 2008. Only a Final Draft report work product is available, dated 2-7-2010. The audit scope included capital project materials and labor charges. The audit report did not address project labor.

  - All audited projects were built in accordance with one-line diagrams and field drawings.
  - PJDs did not capture the full extent of the project and change orders were seldom provided.
  - In several cases, equipment no longer in service remained within new/upgraded facilities.
  - Vegetation was found growing in substations beneath equipment.
  - Several projects audited experienced budget cost overruns.
  - Nearly half of the materials invoiced to projects had control issues:
    - Material purchased without corresponding quantity used.
    - Unknown materials used.
    - Materials used that do not correspond to project scope.
    - Missing information such as vendor, invoice number or charge numbers.
    - Manual entries for material used without substantiation.

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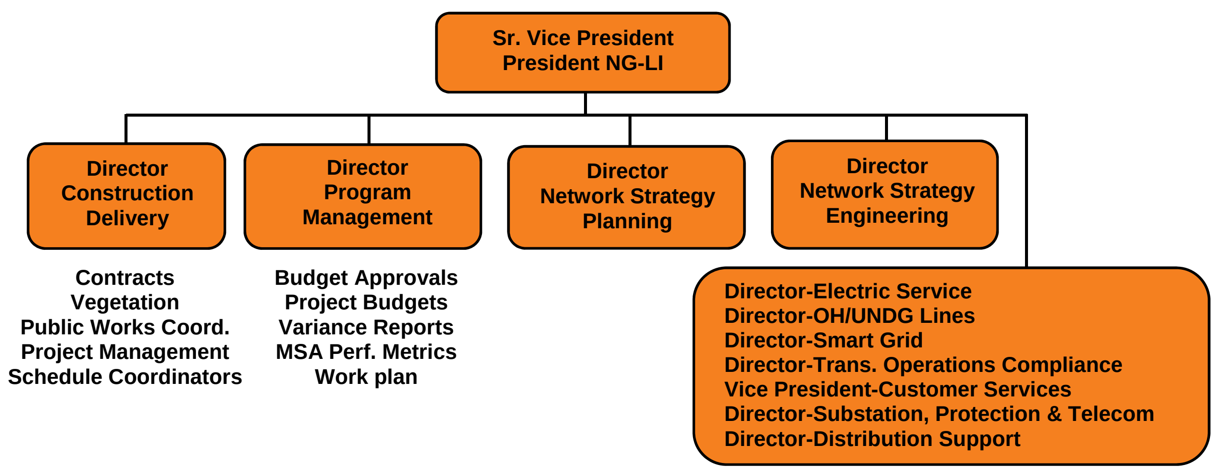
[12] DR 698
[13] DRs 38 and 698

- In one case, LIPA was charged over $2.2 million for over 20,000 ft. of unused cable. While approximately $612,000 of the cable purchase was transferred to other accounts, the remaining cable was salvaged. Transfer/credit of the salvaged cable could not be verified by National Grid.
- Vendor invoices were missing purchase orders, timesheets and work descriptions.

- Recommendations presented in this audit required that National Grid:
    - Develop a full scope document following approval of the project for inclusion in the following year budget.
    - Document and implement a capital project close out process. Full documentation should minimally include PJDs, change orders, one-lines, field drawings, budget versus actual analysis, third-party contracts, documentation of transfer/return credits, and lessons learned.
    - Improve the documentation of project costs. Accounting practices did not permit LIPA to see the actual project cost reporting.
    - Review, update and improve substation maintenance and facilities.
    - Organize and retain all third-party invoices with supporting information.

- National Grid's organizational resources for T&D program and project management are similarly limited. Functional units for monitoring project cost and schedule reporting are organizationally separated, further reducing their potential effectiveness as illustrated in **Exhibit 10-2**.

Exhibit 10-2
National Grid Long Island Organization



10.3.5 National Grid's project management policies and procedures are deficient in the areas of project organization, planning, authorization, execution, monitoring, and management control.

- Program and project management policies and procedures consist of:[14]

  - Budget Process
  - Variance Analysis
  - Change Control Process

- Roles and responsibilities for project manager, engineer, sponsor and other organizational interfaces are minimally defined.

- Policies and procedures for project estimating, project cost management, schedule management, progress inspection and reporting, completion and close out are not available.

10.3.6 Capital project cost control lacks objective and independent oversight. Cost estimating is done by the same resources that are responsible for determining capital project costs.

- Network Strategy Planning and Engineering organizations provide conceptual (C) estimates for the capital improvement program budget submittal. This is a single dollar amount without detail or supporting economic analysis.

- Construction, Contracts and Engineering organizations estimate their respective labor, materials and contractor spending levels for the year. These budget (B) estimates are used to stay within LIPA annual budget limits and are not "project" cost estimates for the entire project.

10.3.7 Capital project cost management is ineffective.

- Tracking of project dollars already spent does not provide a meaningful performance measure.[15]

- Analyses of "total project" cost estimates to actuals are not done. The focus on project cost is strictly limited to spending within the annual budget limits and associated variance reports.

- National Grid's policy requires monthly project cost analysis to determine variances.[16] The policy does not promote timely information or effective project cost management. According to the Variance Process, twenty business days after the monthly financial closing, the Program Management Manager will submit a variance report to LIPA's VP of Operations. This report is available from the Program

[14] DR 79
[15] DR 79
[16] DR 86

Management Variance Analysis program, and will contain by category sequence of programs in the budget, costs to date, scope changes, final cost projections, and variance information. For any variance +/- $1 million, or where the variance is considered significant by the Manager of Program Management, an explanation of the variance will be included.

- Project expenditures reported monthly are retrospective, not active or projected project cost management.

  - Variance reports of capital project expenditures are reported for the entire program or project based on the annual spending levels anticipated. They are not tied to detailed project cost estimates. **Exhibit 10-3** provides an example of the variance report level of detail.[17]
  - The variance report example was produced August 15, 2012, for spending data ending June 2012. While this may be twenty days after the monthly financial closing, this is not prior month data.
  - National Grid Program Management Analysts coordinate spending data with Project Managers on a more timely basis than the variance reports. Nevertheless, spend data is after the fact.
  - Spending overruns are netted against underruns and projected year-end amounts. This is not project cost management.
  - A negative variance is shown for projects deferred and netted against project overruns showing that the variances are "budget" not project cost oriented.
  - Spending overrun comments in the variance report note "scope changes being submitted for approval" in a number of cases – seeking approval after the fact.

- National Grid's variance report submitted to LIPA appears to make the Change Control Process irrelevant as "scope change to be submitted" is shown for comments on project variances in cases exceeding $1 million already spent. Scope changes are required as follows:

  - 1.1 Definitions

    1.1.1. Scope Change / Changes to Scope - All changes to the baseline scope that accumulate to plus or minus $25,000 must be documented by a scope change. A scope change to a project may include a physical change, a change to the planned in service date, a change or requirement imposed by an outside agency that changes the scope as defined in the Project Justification Document, a change to project location, or even the addition of a new project.

[17] DR 195 June 2012 Variance Report

Exhibit 10-3
June 2012 Variance Report – Example Page

LIPA Capital Budget - June 2012

	Major/ Routine	Approved Budget	Approved Scope Additions	Pending Scope Additions	Returns	Revised Budget	Actuals to Date Thru 06/30/2012	Current PYE	Variance	Comments
Purchase Tools & Equipment - Meter Section	R	$150,000	$0	$0	$0	$150,000	$13,881	$150,000	$0	
Electric Class of Customer, cost of service	R	$170,000	$0	$0	$0	$170,000	$32,597	$170,000	$0	
Hybrid Bucket Trucks	R	$0	$0	$0	$0	$0	$0	$0	$0	
		$17,574,500	***$0***	***$0***	***$0***	***$17,574,500***	***$9,762,934***	***$18,037,811***	***$463,311***	
02 – EDC										
Replace Transmission Poles	R	$2,080,800	$0	$0	$0	$2,080,800	$817,533	$1,880,800	($200,000)	
Replace Distribution Poles	R	$6,000,000	$0	$0	$0	$6,000,000	$4,218,070	$6,000,000	$0	Burdens booked for accrued 2011 invoices
Tel Poles Transfers	R	$2,080,800	$0	$0	$0	$2,080,800	$1,520,805	$2,230,800	$150,000	
Minor Extensions - Customer Requests	R	$5,100,000	$0	$0	$0	$5,100,000	$3,760,074	$6,294,776	$1,194,776	Overrun offset by UG underrun
Minor Extensions - O/H Capital Reactive Maintenance	R	$2,500,000	$0	$0	$0	$2,500,000	$3,051,626	$5,108,756	$2,608,756	Job counts in all Divisions are much higher than previous years; several large jobs in 2012: Rte 25A, Muttontown; Gardiners Ave, Levittown; Terrace Dr, Great Neck; and Colonial Springs Melville Review of the program in progress.
Minor Extensions - System Deficient Conditions	R	$0	$0	$0	$0	$0	$131,021	$219,343	$219,343	
Minor Extensions - U/G Capital Reactive Maintenance	R	$6,400,000	$0	$0	$0	$6,400,000	$3,274,626	$5,482,084	($917,916)	Underrun offset by Customer overrun
Accidents to Property	R	$3,327,850	$0	$0	$0	$3,327,850	$2,340,721	$4,046,519	$718,669	Three large accidents in Queens Nassau and Central Nassau totaling $448K
ED&C Capital Tools	R	$325,000	$0	$0	$0	$325,000	$144,538	$340,482	$15,482	Review of Capital Tool spending in progress. We expect this to have a zero variance.
New Business	R	$20,000,000	$0	$0	$0	$20,000,000	$9,896,495	$19,165,000	($835,000)	
CIPUD	R	$650,000	$0	$0	$0	$650,000	$342,382	$563,750	($86,250)	
RUD	R	$3,200,000	$0	$0	$0	$3,200,000	$1,057,227	$2,260,000	($940,000)	

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- It is implicit in this definition of Changes to Scope that variations in project "cost" plus or minus $25,000 would require a scope change. Nevertheless, National Grid makes a distinction without difference as cost changes alone do not require change requests

- Scope changes are requested and recorded for "documentation purposes." A log was provided but there are no analyses or summaries prepared for management. There is no indication of what happens to a scope change request that been rejected or any reason given.[18]

10.3.8 National Grid's capital project schedule management is ineffective as a project management tool.

- National Grid could not produce "project schedules" and "schedule progress" reports. NorthStar requested weekly schedule progress reports for specific construction periods in CY2012 and CY2013 as were described in interviews. National Grid provided work plans (progress reports) representing the Overhead/Underground lines work performed for the 2012 year end, and the work performed/scheduled for 2013. No weekly or bi-weekly reports could be provided to demonstrate schedule management. National Grid stated that yearly summary reports were provided because system limitations do not allow prior bi-weekly reports.[19]

  - Bi-weekly schedule progress reports purportedly show project identification data, work plan start and finish dates, man-hours expended and percent complete.
  - This is a report of hours charged against jobs, not the "program" or "project" schedule performance.

- Work plans list man-hours to perform the jobs listed in areas of design, testing, and field construction. Schedule progress reporting is limited and only includes: ready, in-process, complete, on hold or deferred (normally to the following budget year).

- National Grid stated that the following reports are used by managers to assist them in monitoring and achieving both capital and O&M budget targets.[20]

  - Variance Reports, described above, are produced by the Program Management Department. National Grid stated that they are used by Project Managers to determine the status of their projects and used by the Analysts to project final costs for projects and program work. However, variance reports provide information on project dollars spent months prior – therefore, they do not determine status – nor do they project final costs, as the data is retrospective.
  - Work plan reports are produced by Program Management Analysts and are purportedly used to determine project status and resource requirements. Project status is determined as "in-process, completed, on hold, or deferred." This level

[18] DR 850
[19] DR 293
[20] DR 82 and 194

of detail may be used to determine "status" at a very high level, but is insufficient to satisfy project schedule management.

- Work plan information is limited and at a very high level:
  - Gantt Charts – Show a bar chart of project activities
  - Histograms - Show resources required for the workplan
  - Overtime (OT) Assessment - Shows the OT rate by resource by division

- National Grid indicated that the following reports are also produced by the Program Management Analysts.

  - T&D Weekly - A tabular report showing the count of substation, transmission, and distribution projects for the calendar year.
  - Summer Prep Report - Lists critical activities and status required for completion prior to the summer.
  - CIP-2012 Tracker - Tracks the status of the Circuit Improvement Program.
  - TLM Report - Tracks the status of the Transformer Loan Monitoring program
  - Cable Requirements reports are produced by Program Management and are used to ensure that adequate material is on hand to begin project work.
  - Cable Requirements (750 Cu, 1000 Al) - A report showing required cable quantities and need dates.

- NorthStar requested specific project management documentation for a limited number of selected projects to verify project reported information.[21]

  - Project conceptual estimates were requested and supplied for all capital projects. However, these were budget year only and do not represent the entire project.
  - Total project cost data from initiation to completion was requested.
  - In Service Dates satisfied Need Dates for those projects selected.
  - Project schedule information was meaningless:
    - Numerous cases where job start dates and finish dates were the same.
    - Numerous cases where thousands of man-hours were recorded for the same day.
    - Single activity items listed showed schedule start to finish periods exceeding two years.
  - Third-party contract amounts spent on the projects were known, but contract estimates, bid amounts, selection documentation and contract award information were generally unavailable.

- Project conceptual estimates to budget estimates show dramatic differences.

- LIPA/National Grid was unable to provide a comprehensive list of recently completed projects.[22]

[21] DR 642
[22] DRs 83 and 700

- A selection of capital projects from the 2010 and 2011 budgets was made to compare project budget amounts to actual expenditures and is shown in **Exhibit 10-4**. All of the projects selected spanned multiple calendar years. A review of the eleven projects found:

  - Five are in service at the time of this report. All were in service later than the year of the conceptual estimate.
  - Two projects were deferred.
  - Four projects are under construction but will be in service at a time later than the conceptual estimates.
  - **Exhibit 10-4** provides cost details of the projects selected for detailed examination that are in service and others that have incurred significant expenditures against budget. LIPA/National Grid was unable to provide progress (percent complete) of active projects to determine if the level of expenditure tracks progress.[23]

Exhibit 10-4
Project Cost to Budget Estimate (dollars in thousands)

Project ID	Description	Approved Budget	Actual Cost	Spend Variance	Comments
D25844	T100656141 – Brightwaters to Captree Cable Replacement	$17,458	$19,965	Overspent 13%	Cost to date. Project is not complete.
D26999	T100648153 – Bridgehampton – Install new transmission substation	$12,556	$ 2,972	Underspent 322%	Project work performed $3M, then project cancelled.[24]
D33620	T100618274 – Orchard Add 3rd 28MVA Transformer	$ 0	$ 640	Overspent 100%	Project work deferred.
D33671	T100753745 - Great Neck to Lake Success – Install third 69 kV Cable	$12,579	$ 7,884	Underspent 60%	In service
D40518	T100885704 - Far Rockaway Sub – Terminal Work	$ 3,207	$ 4,122	Overspent 22%	In service
D52754	T100887648 - Central Islip Zig Zag Transformer	$ 1,479	$ 1,470	Underspent 1%	In service
D53492	T101096515 - South Manor Intall 2-33 MVA 69-13 kV Banks	$ 2,700	$ 1,991		Cost to date. Project is not in service and work deferred.
D59805	T101191827 - DRSS at Holtsville	$ 8,072	$ 7,131		Cost to date. Project is not in service

Source: DR 642

- A single report of active projects showing original "project" cost estimate to current estimate, schedule and percent complete does not exist. The work plan does not include project cost information.[25]

- For projects selected to provide examples of project specific information, LIPA and National Grid could not provide the following in a timely manner:[26]

[23] DR 82, 83, 84, 195, 387 and 700
[24] Information from National Grid obtained in fact verification.
[25] DR 701
[26] DR 642

- Project-specific schedules and schedule updates showing that the "project" activities (versus the work plan) were managed.
- Contract data for 2013, even though a number of projects were active in 2013.
- Field inspection reports.
- Progress inspection reports, whether documented by National Grid, LIPA, or another party.
- Quality assurance reports.
- Final completion reports or project completion documentation.

10.3.9 Contractor selection and bidding for project work is poorly documented and could not be reviewed.

- National Grid stated that all project work directed to a third party contractor requires the development of a bid specification, a contract strategy and a constructability review. This information along with the drawing/specification package is forwarded to Purchasing for solicitation of a competitive bid utilizing a pool of pre-approved contractors. An evaluation is conducted from both a commercial and a technical perspective and the lowest cost submittal which complies with both the commercial and technical components of the bid is awarded the project.[27]

- Contract oversight for transmission, substation and control & protection projects are field managed through completion by Construction Management including receipt and turnover of as-built drawings. All third party construction for distribution projects are field managed through completion by Overhead/Underground lines including receipt and turnover of as-built drawings for historical purposes.

- Contract information, bid and selection documentation, field inspection reports and final completion reports and related documentation supporting projects currently being constructed and recently completed that were selected for detailed audit examination were not readily available. National Grid stated that the Construction Delivery organization would require approximately a month or so to gather all of this documentation.[28]

10.3.10 Contractor oversight is minimal, informal and undocumented.

- National Grid's Construction Delivery organization uses an Internal vs. External Resourcing Guide to determine in-house versus third-party contractors for capital project construction work.[29] Its stated objective is to optimize utilization of internal resources. Contracting decisions are made as the work plan is developed.

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[27] DR 79
[28] DR 642
[29] DR 87

- National Grid described third-party contractor oversight as follows:[30]

  - All Major Capital projects may require construction resources from both contracted work force as well as in house labor work force.
  - National Grid's Construction Delivery Project Management organization includes Project Managers and Construction Management that are responsible for overseeing major capital projects within their jurisdiction and schedule compliance.
  - Project Managers and Field Coordinators work with internal operating organizations to balance work plans across divisional boundaries as a basis for sourcing strategies for particular projects throughout a capital program year.

- Project Managers address schedule and completion commitments in work plan status meetings with the associated stakeholders.

10.3.11 LIPA and National Grid do not manage quality assurance and quality control at the program and project level.

- National Grid does not have specific written policies/procedures that relate to quality assurance/control activities for program and project level work.[31]

- National Grid stated that work performed by either in house work force or a third-party contractor is overseen by first and second level supervisors responsible for that work force. This oversight includes monitoring the quality of workmanship and adherence to LIPA specifications. The supervisory work force is expected to correct any identified substandard condition as it is encountered. National Grid stated that the quality of work performed by contractor resources on a given project is assessed and documented on a project summary form. This information is utilized to assess the overall performance of the various contractors that are approved to provide services on LIPA's T&D system.[32]

- National Grid examples of contractor work completion reports but did not provide documentation of work in process.[33]

- National Grid stated that Network Strategy Engineering personnel perform random audits of capital projects being constructed or recently completed. These audits are designed to inspect the quality of the construction and adherence to the design documents issues as well as LIPA's construction standards.

- No such audits could be provided.

- As noted above, National Grid and LIPA could not provide documentation supporting field inspection reports, progress inspection reports, quality assurance reports, final

[30] DR 88 and 642
[31] DR 76
[32] DR 75
[33] DR 642 and fact verification.

completion reports or project completion documentation in a timely manner. This documentation should be readily available for active and recently completed projects if National Grid rigorously performed the activities described.

10.3.12 The OSA covers capital improvements and PSEG-LI project management obligations in a similar manner to the MSA, but with less specificity.

- With regard to capital program and project management, the OSA scope is comprehensive and covers preparation of:[34]

  - Recommended capital plans and monitoring of the approved annual capital budget.
  - Risk assessments and analyses in support of capital projects prioritization and planning.
  - LIPA's long and short range system plans, including integrated electric resource plans.
  - LIPA's proposed annual operating and maintenance work plan.
  - Preparation of long and short range transmission and distribution planning analyses and forecasts to determine the need for capital improvements, including introduction of smart grid and other emerging technologies and project management services to ensure the technical performance and reliability of the T&D system, and to meet LIPA's financial, customer satisfaction, and regulatory compliance goals in accordance with LIPA's electric resource plan and its short and long range financial objectives.
  - Performance of capital improvements and supervision of capital projects including engineering and related design and construction management services and repair or modification activities required due to Public Works Improvements.
  - Preparing and monthly monitoring of budgets necessary for both capital and operating expenses for the services provided by the Service Provider under this Agreement.
  - Analyzing monthly and year-to-date budget to actual variances, providing explanation of such variances and formulating financial projections based on the variance analyses.

- LIPA retains the ultimate authority and control over the assets and operations of the T&D system, and the right to review, amend as appropriate and approve the annual operating budget, capital budget and energy efficiency budget pursuant to the procedures outlined in the Contract Administration Manual and approve or in its discretion, develop, all long-range strategic plans for the T&D system and system power supply.[35]

- Under the OSA, wages, salaries, benefits, pensions, other post-employment benefits and other labor and labor related costs of the general workforce, including ServCo benefit plan expenses incurred by ServCo in performing operations services,

[34] DR 4, OSA Section 4.2 – Operations Services
[35] DR 4, OSA Section 4.4 – Rights and Responsibilities of LIPA

including capital improvements are defined as “pass through expenditures” without any mark-up.

- LIPA and PSEG-LI acknowledge and agree that each annual operating budget, capital budget and energy efficiency budget and the related ServCo staffing levels initially approved by LIPA for each contract year shall be designed to be adequate in both scope and amounts to reasonably assure that the “Service Provider” (PSEG-LI) is able to carry out the related operations services in accordance with the contract standards and have a reasonable opportunity to earn incentive compensation under the performance metrics.

- In developing the proposed budgets, the OSA requires the Service Provider to provide LIPA with alternatives and plans designed to achieve the desired goals in a cost effective manner and demonstrate the cost effectiveness and the appropriateness of the proposed alternatives and plans to LIPA. The Service Provider will actively manage to the approved budgets and related work plans and shall keep the Joint Operating Committee (JOC) informed not less frequently than monthly on the spending levels against approved budget amounts and work plan status and proactively offer cost reduction and cost reallocation recommendations to the JOC. They further acknowledge and agree that it may, from time to time, be necessary or appropriate to amend or otherwise adjust the annual operating budget, capital budget or energy efficiency budget as approved, or the related work plans thereunder, as well as the performance metrics, as a result of force majeure, LIPA fault or other reasonably unanticipated events which have resulted in schedule delays or increased work scope or costs.

- As a result of recently passed NYS legislation, it is unclear how JOC activities will be performed under the OSA, if at all.

10.4 Recommendations

LIPA’s program and project management needs are so significant, that the following recommendations for improvement are a primer for establishing the basics of a project management function. As such, additional explanation is included to provide a context for the recommendations made.

10.4.1 Adopt PSE&G’s Project Management Playbook as a baseline for managing capital projects.

PSE&G’s Electric Project Manager Playbook and its supporting documentation is a tool to help guide the project manager to successfully initiate, implement and complete assigned projects safely, on schedule and within scope and budget. Using the Playbook, the project manager is able to identify the tasks and responsibilities required to complete all electric delivery projects. It outlines a consistent process to manage all projects through the Project Manager position.[36]

[36] DR 295

The Project Manager Playbook follows a standardized method of identifying, planning, scheduling, executing and closing out of all projects within the project portfolio utilizing the established steps of the electric project delivery process. It includes comprehensive identification of activities and tasks required, as well as appropriate approvals, detailed planning, and integrated execution of the work to successfully complete all projects. The Project Manager Playbook addresses the following:

- Purpose
- Goals
- Execution
- Overview
- Methodology
- Business Relationships
- The Five Project Phases, Activities & Tasks
    - Project Initiation
    - Preliminary Engineering/Design
    - Detail Engineering/Design
    - Construction
    - Completion
- Supporting Documentation
- Cross-References
- Terms & Definitions

The Playbook will require editing and modification to adapt to the LIPA project environment. Many of the items/topics requiring adaptation are listed in the Playbook Supporting Documentation (Appendices 1 through 3 and Attachments 1 through 13). Nevertheless, this should be done immediately. PSEG-LI management and supervisory personnel need to be indoctrinated in its use.

In addition to the Project Manager Playbook, NorthStar offers the following recommendations to strengthen LIPA's program and project management function.

10.4.2 Develop formal capital project management policies and procedures that support the Project Management Playbook.

- Update and implement policies and procedures for initiating, developing and executing capital projects.
- Define specific roles and responsibilities for the planning process.
- Require more frequent (than annual budget development) formal reviews of all major development plans, capital programs and projects, and maintenance tasks.
- Perform project analyses to determine effects on other development projects and report recommendations to senior management for project approval, prioritization, and resource allocation.
- Formalize policies and procedures for contract administration and change order control.
- Define the role of project manager within the LIPA and PSEG-LI organizational structure.

The benefits from these implementation activities will improve oversight and controls over project scope, economic alternatives to capital projects, authorization and spending, will minimize project cost overruns and reduce project re-work. In terms of project cost overruns, estimating accuracy is in all likelihood the greatest contributor to the variance between estimates and actual completion costs.

10.4.3 Define deliverables required for each project phase and establish criteria for completing each project phase. Include all elements of a project life cycle from planning to closeout.

- Project Justification Documents should include, along with the existing formal project request and detailed scope: proposed project location, specific user requirements, facility requirements, environmental concerns, required utilities, schedule detail, a budget estimate based on project experience, funding, financial analysis, and other relevant elements of the project.
- Establish an official "project" budget at the initiation of a project separate from the annual spending estimates currently done. This amount should not change throughout planning, design, or construction without sound rationale documentation and management approval.

10.4.4 Define project management performance measures focusing on the effectiveness of cost estimation and scheduling. Cost estimates and schedules developed for preliminary plans should be evaluated when a project is complete to determine where further enhancements to project estimating can be made.

The benefits from the implementation of this recommendation will improve productivity and management focus, timely identification and resolution of project issues that result in project cost increases, and the effective utilization of LIPA's capital budget. Implementation of this recommendation will provide focus on roles, responsibilities and accountabilities for performance, and minimize the potentially negative effects of conflicts in organizational roles and responsibilities.

- Have project managers actively monitor overall project progress against the baseline schedule and review cost versus progress and budget.
- Formalize project management performance reporting to LIPA and PSEG-LI.

10.4.5 Utilize a WBS in the initial phases of the project justification and conceptual estimating, and continue their refinement as the project progresses.

Effective capital project management uses a hierarchical WBS to organize project elements into logical bundles of functional work representing discrete work activities that enable scheduling, resource loading and objective progress measurement. The WBS provides the basic framework to plan, execute, and manage the project. WBS coding permits precise identification of project elements to allow accurate project management, budgeting, communication, cost reporting, scheduling and performance. Supporting actions to this recommendation include:

- Develop well-defined work packages that can be used to track and measure project performance.
- Plan work in logical work groupings or packages and subdivide into smaller work groupings. Ensure that activities required to perform the work in each group are identified, defined, and dependent relationships established.
- Formalize the use of WBS elements by all project participants in their respective areas of responsibility and as an identification tool for project management performance measurement.
- Use the WBS in procurement/contracting activities and specify the WBS in contractor Requests for Proposals.
- Use the WBS for project costing and as a means to assess the impact of programmatic changes in funding levels on work content, schedules, and contractual support.
- Prepare cost estimates for each WBS element to assist budgeting and project validation.
- Integrate the WBS with LIPA/PSEG-LI's accounting (such as SAP) systems, project cost management systems and schedule management systems.
- Integrate master work plans and detailed contractor schedules / activities to the WBS to permit integration of schedule information and to facilitate review of status reports and change proposals.
- Evaluate the feasibility of automated capital project cost management software for tracking the projects and the use of WBS to allocate costs and relationships to budgets/funding sources for projects.
- Refine detailed project estimates initially prepared by WBS element and follow the manner in which the project work was planned, scheduled, estimated, funded and executed.

10.4.6 Address the deficiencies in project estimating by making organizational and process improvements and creating a capital project estimating function/organization equipped with appropriate tools.

- Establish an organizational group of professional estimators for transmission and distribution that will develop estimates for planning, engineering and construction. Use these internal estimators to set and validate baseline estimates established for contractors.

- Establish project estimating tools such as a formal data base of project estimates and support tools such as software and develop and manage an estimating true-up process.
- Continuously verify the accuracy of estimates versus the actual project cost.

10.4.7 Develop a capital project cost forecasting / trending capability.

Major capital projects are implemented over a significant time period and determining the actual cost of materials and services is critical to project justification, alternatives analysis and performance management. Cost forecasting and trending analyses predict the actual cost of materials and services at a future point in a project and are based upon various considerations for inflation, escalation, and market forces. Forecasting and trending analysis begins with initial project estimates and project schedule assumptions. Trending allows the early recognition of project issues that may result in deviations from the approved cost and scope of work. The identification of trends allows management the opportunity to intervene and control issues before they become problems. Recommended support activities in this control area include the following.

- Assess the process used to develop and update estimates for completion.
- Review inflation and escalation factors and analyses used to predict project completion costs.
- Review project budget numbers and cost reporting information to determine whether they represent the most currently approved budget and cost data.
- Determine whether cost and schedule systems are integrated and whether the project master schedule is appropriately integrated with the approved project budget.
- Assess the frequency of project cost reviews at various levels of detail and at various stages of project completion.
- Review project guidelines for performing trend analyses and exception reporting.
- Evaluate how trends were identified, analyzed, brought to management's attention, and how they were resolved.
- Determine whether cost control systems, forecasting and trend analyses directed attention to bulk rates, commodities and productivity to reveal above/below average performance.

10.4.8 Incorporate contingency management in capital project cost estimating and cost management.

It is critical that project budgets include contingency funds based on baseline estimates and their relative risks. In addition to project specific contingency elements, a contingency should also be established to address project scope changes and the need for unforeseen administrative or legal support. In order to audit contingency management, the following activities should be included:

- Review the project budgets and individual budget elements including management, design, construction and project specific contingencies.
- Determine whether contingency levels were appropriately evaluated and reviewed in each evolution of project estimating and each project stage.

- Relate contingency levels with recognized uncertainty and risks at specific levels of planning, design and construction.
- Evaluate project design for unforeseen conditions that might arise or be discovered during the design process and whether these conditions fall within the original project scope (i.e., the program requirements initially articulated by the user in the project definition stage).
- Establish and formalize project cost contingency to cover additional project detail such as unforeseen site conditions, interference, delays or other circumstances that would not have been known at initiation, and expanded or changed project scope not identified during the scope definition phase.

10.4.9 Formalize capital project change order management controls.

When capital projects are "actively managed" rather than reported retrospectively, change orders frequently surface as an indication of the need for specific remedial action. A common perception is that the change orders reflect a breakdown in scope control, procurement or contracting controls. However, change orders may be systemic in nature and more directly related to shortcomings in project planning and project management. Capital project change order management should include:

- Policies and procedures should be developed for documenting and approving change orders covering purchase orders, contracts and scope change management.
- Complete documentation files on change requests, justification, and related correspondence. Presently, LIPA and National Grid policies and procedures do not require procurement/contracting change order logs and documentation.[37] This must change to allow project management. Also, project scope changes are recorded by National Grid, but they are after the fact and not analyzed for project management improvements.[38]
- Document retention requirements for all change orders issued for major project contracts.
- Formal change order approval by an individual with proper authority and independence from project direct oversight.
- Evaluation of then current cost estimates and schedule estimates provided with the change order requests, and whether these estimates were independently verified prior to change order approval.

10.4.10 Improve periodic capital project progress reporting.

In addition to the monthly spending analysis prepared by National Grid, progress reports should be prepared by the Service Provider, and submitted in conjunction with requests for progress payments against construction work in process. Project progress reporting includes reports to PSEG-LI management, LIPA and the Board; and to individuals directly involved in the project, such as the Project Manager, designers, and construction personnel. While it is not necessary that everyone associated with the project receive the same information, it is

[37] DR 640 and 641
[38] DR 850

necessary that the information received is accurate, and that it addresses areas of concern, cost and schedule issues, and recommendations for action. Project progress reports should be timely, and contain all information which is pertinent for their target audience. Project report information includes:

- Project cost variances
- Schedule variances
- Committed costs and actual costs to date
- Estimated cost at completion
- Capital budget impact
- Trends
- Pending and approved scope changes
- Earned value, or other measurements of cost and schedule performance.

10.4.11 Improve capital project document control.

Document control is a systematic approach to managing critical project documentation such as manuals, plans, work instructions, drawings, specifications, and other information. It includes the indexing of documents; security and control of document content; as well as distribution of documents to authorized users and removal of obsolete documents from circulation. The primary purpose of document control is to insure that only current and approved documents are employed in the planning, development and delivery of capital projects. Inadequate document control can lead to project staff and/or contractors using outdated forms, project specifications, drawings and procedures resulting in inferior work products or project implementation, rework and, ultimately, to increased costs and lost time.

10.4.12 Perform capital project schedule management.

The development of a realistic project schedule is a critical element of project management and is directly tied to the economic and operational justification of the project. Scheduling establishes and monitors target start and finish dates, and is critical to the execution of the project. In general, the planning process starts with the development of a top-level master schedule, and is supported by a project-level critical path schedule and subordinated detailed control level schedules to manage day-to day activities. Schedule management requires clearly delineated responsibilities from the outset. Recommended support activities include the following.

- Establish processes for systematic schedule preparation, review and analysis.
- Integrate cost and schedule systems with the project master schedule and the approved project budget.
- Develop a baseline schedule for every capital project showing the logical relationships, duration, and timing of the WBS elements for engineering and construction.
- Periodically, perform analyses of the initial establishment of operation/completion dates.

  - Construction delivery strategy – whether plans were developed and defined for construction contracting and long lead item equipment procurement.
  - Phasing requirements – determining the proper sequence and phasing of all proposed construction work on the project to ensure that construction was accomplished in the most economical manner while minimizing impact to operations.
  - Integration of design, procurement and construction activities - once phasing was determined, whether all activities concerned with design, procurement, construction, start-up and operation, and the entire scope of work was clearly defined and integrated.
  - Milestones – identification of important milestone dates establishing a basis for the implementation of the project work plan.

- Periodically reassess processes used to obtain actual project schedule data used to determine the status of the project against key milestones, and the accuracy of information on the progress of individual/critical project elements.
- Formalize processes to address proposed and actual revisions to the project schedule, and use of the scheduling system to identify possible solutions for schedule recovery.

11. CAPITAL AND O&M BUDGETING

This chapter focuses on LIPA's management and oversight of its capital, operations and maintenance expense budgeting process.

11.1 Background

LIPA's operations and maintenance (O&M) expenses are budgeted at $1.046 billion for 2013. O&M expenses are comprised of costs related to the T&D system Management Services Agreement (MSA) and Power Supply Agreement (PSA) with National Grid, which contain the costs associated with operating LIPA's T&D system and providing generated power. The MSA and PSA with National Grid total $759.5 million, or 73 percent of all O&M expenses. A summary of O&M expenses for 2013 is shown in **Exhibit 11-1**.

Exhibit 11-1
LIPA Expense Budget Highlights - 2013

O&M Expense Item	2013
• MSA and PSA with National Grid	$759.5 million
• LIPA's Efficiency and Renewables Program	$117.4 million
• New York State (NYS) assessments including the NYS Temporary Energy and Utility Conservation Assessment enacted in 2009	$ 41.4 million
• NYS Administrative Cost Recovery Assessment	$ 8.2 million
• Storm restoration costs	$ 52.0 million
• O&M activities associated with LIPA's 18 percent ownership interest in Nine Mile Point 2 nuclear power generating plant	$ 32.9 million
• Losses on uncollectible accounts	$ 21.0 million
• Professional services, consisting of outside engineering, financial, legal and other professional services	$ 16.4 million
• Property and revenue-based payments-in-lieu of taxes (PILOTs)	$342.3 million
• Depreciation and amortization expenses primarily related to capital investments in the T&D system	$277.5 million
• Interest expense relates primarily to tax-exempt borrowings.	$331.7 million

The capital budget approved for 2013 totals approximately $448.1 million net of third-party reimbursements. The budget includes additions and betterments to the T&D system ($288.6 million, net), transition costs associated with the Operating Services Agreement ($120.9 million), proportionate share of capital related to Nine Mile Point 2 nuclear generation ($35.0 million), and LIPA information systems, equipment, and miscellaneous items ($3.6 million).

LIPA's operating expenses consists primarily of contractual obligations (e.g., MSA and PSA) and non-discretionary costs (e.g., PILOTS, NYS Assessments, bond interest expense). LIPA lacks direct control over a substantial portion of its budget under its current operating structure. T&D O&M expenses under the MSA are fixed in nature and LIPA lacks transparency with respect to the make-up of such costs.

Typically, capital and O&M expense budgeting are separate but closely related processes. Capital budgets are often driven from the top down by broad organizational needs such as customer and load growth and restrictions related to the capability of the utility to fund needed capital projects. O&M expense budgets are more often developed from the bottom up with recognition of the immediate physical needs of the system as well as long-term maintenance priorities. However, O&M expense budgets are often affected from the top by the same sort of funding restrictions that affect capital budgets. Because budgets are affected by both upper level (executive management) and lower level (line and operations) management, it is critical to review the roles of all levels involved in the budget development processes.

The review of budget processes must determine how and in what way needs-based information is incorporated. It must also determine what limitations on budgets are placed from the top down and the basis for these limitations. For example, in the case of investor-owned utilities, are top-down restrictions based on predetermined profit margins and rates of return? Similarly for public utilities such as LIPA, are budgets simply dictated by rates and revenues? In previous reviews NorthStar has identified weaknesses such as the following:

- Managers at inappropriate levels make decisions in the budget preparation process.
- Managers apply inconsistent rationale in decision making.
- Cost effective, efficiency improvements, and long-term maintenance priorities consistent with safety and reliability standards are deferred due to lack of capital.
- Decision-making criteria are not well-articulated or documented and are not consistently applied across all business units.
- The budgeting process does not have sufficient input from the bottom.
- The interface between workforce planning and the budgeting process is not clearly described and effectively implemented.
- Budgets and the related variance/management reporting processes are not consistent with operational plans or the implementation of those plans.
- Reports provided to managers are not useful in assisting managers to exercise their business responsibilities. Too often financial reports do not provide the appropriate detail and structure needed by operations managers.

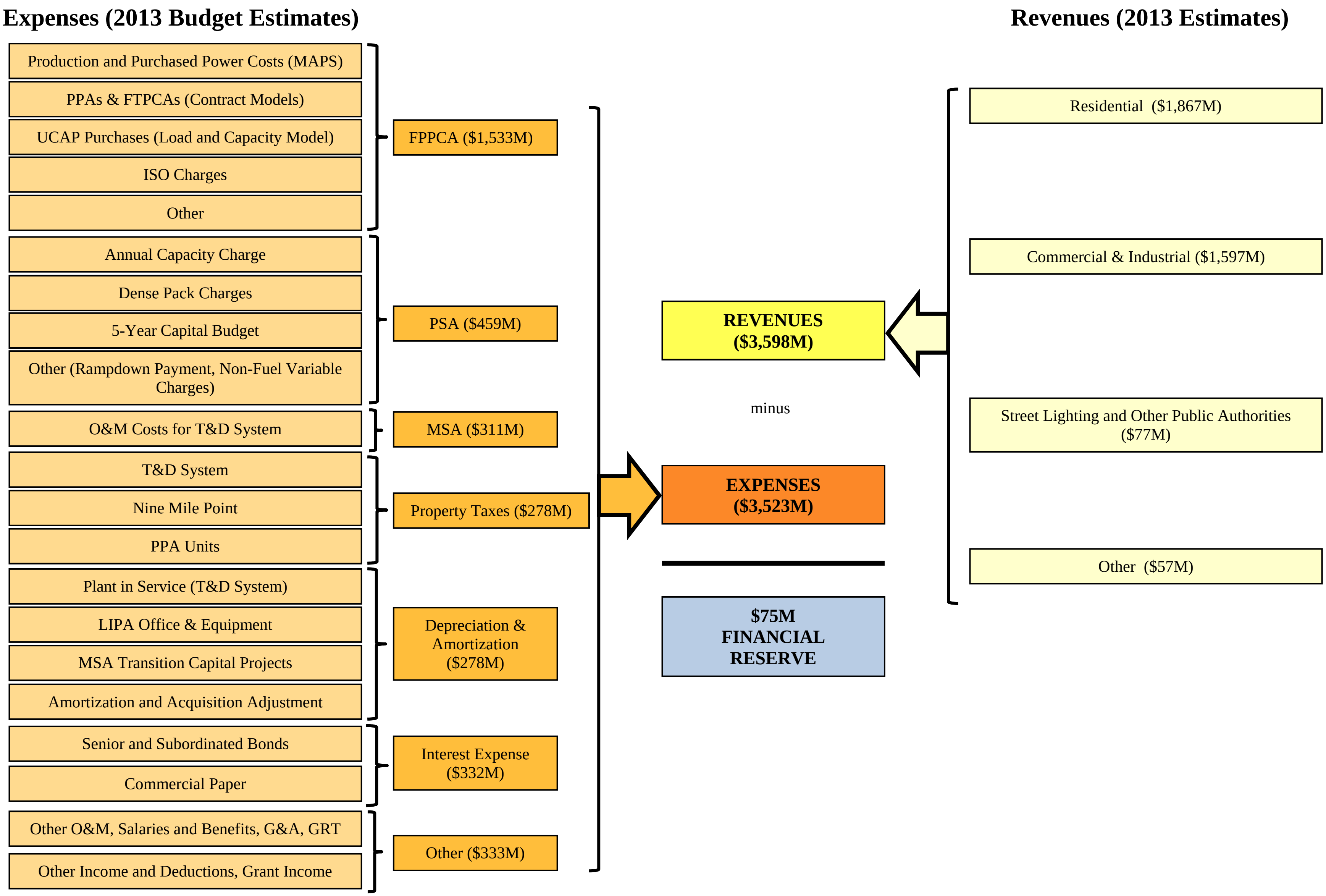
At a high level, LIPA's finance and budgeting process attempts to balance expenses with revenue as illustrated in **Exhibit 11-2** on the next page.[1]

11.2 Evaluative Criteria

- Is the capital budgeting process documented, adhered to, appropriate and effective?
- Does LIPA have an effective methodology for prioritizing and approving capital projects?
- Do allowed revenues/rates and financing opportunities or constraints adversely affect budget levels and priorities?

[1] Typical Uses of Financial Model, IR 142

Exhibit 11-2
LIPA Financial Model



- Does LIPA use budgeting guidelines, practices and procedures, including "zero-based" and other alternative methods, effectively?
- Are incremental O&M expenses associated with new construction factored into the budgeting process in an appropriate manner?
- Are bottom-up and top-down processes for developing budgets for capital/construction classifications and categories appropriate?
- Is LIPA's cash reserve policy appropriate as it relates to capital and O&M budgeting?
- Is the effect on customer rates given appropriate consideration in the budgeting process?
- Does LIPA use appropriate modeling software in the capital and O&M budgeting processes? Are financing considerations incorporated into the capital and O&M budgeting process?
- Do major capital projects have specific funding sources and are they documented?
- Are capital project bond proceeds utilized as required by the bond covenants?
- Is LIPA's long-term financing plan reasonable in light of system requirements and rate considerations?
- Does LIPA have appropriate policies and procedures for the use of debt financing for capital projects?
- Are the roles and responsibilities of the Board of Trustees, and executive and senior management in the budget goal setting, preparation and oversight appropriate and are they executed effectively?
- Does the Board of Trustees see and have access to a sufficient level of budget detail relative to its budgetary responsibilities?
- Does the Board of Trustees effectively monitor LIPA's debt management practices related to capital project financing?
- Are the reports provided to managers clearly related to the budget and do they provide data that are helpful to managers in achieving budget goals?
- Are relationships among planned/budgeted expenditures and actual expenditures appropriate?
- Are capital budgets managed and controlled?

11.3 Findings and Conclusions

11.3.1 LIPA's capital and O&M expense budget process is conducted over the second half of each year and involves nearly all staff members, many contractors and the BOT.

- The MSA requires National Grid's capital project budget submittal by June 30 each year. LIPA's budget process is conducted by the Business Review Committee (BRC) and is summarized in **Exhibit 11-3**.[2]

[2] DR 755

Exhibit 11-3
LIPA Budget Development and Approval Schedule

Month	Budget Process - Activity
June	• CEO's message and budget schedule distribution • Instruction and templates distribution to departments • National Grid submits proposed capital budget to LIPA by June 30
July	• Preliminary energy efficiency load shapes from National Grid • Proposed budgets due from departments • Preliminary load and energy forecast from National Grid • Preliminary load and energy forecast approved by LIPA
August	• Preliminary sales and revenue forecast from National Grid • Compilation of cost center data and related analyses for BRC • Preliminary fuel and purchased power (and fuel breakdown) from National Grid • Completion of revenues and fuel and purchased power budgets • Proposed T&D and generation capital budgets submitted • Final energy efficiency load shapes • Preliminary income statement developed

September	• BRC Budget Review Meetings
	  - Income estimate / rate implications analyses
	  - Departmental budget overviews
	• Final delivered fuel price forecast from National Grid
	• Final load and energy forecast from National Grid
	• Final load and energy forecast reviewed by LIPA
	• Final sales and revenue forecast from National Grid
	• Initial BOT Finance & Audit Committee briefing

October	• Final T&D and Generation capital budget report for budget book • Final fuel and purchased power from National Grid • BOT briefings
November	• Proposed budgets and five-year financial plan presented to public • Review fuel and purchased power cost estimate – latest price forecast • Review budget and five-year financial plan • Public inputs sessions on proposed budget
December	• Board workshops • Board of Trustees budget approval

- LIPA's budgeting process is developed based upon numerous contractual agreements, sales projections, financing terms, accounting policies, estimated costs of expected activities, and budget comparisons to prior year expenditures.[3]

  - The MSA costs are developed from contractual terms and sales projections,
  - PSA Costs are developed from contractual terms and estimated costs of expected activities,
  - The Efficiency & Renewables budget is based upon market research and program plans,
  - Assessments are based upon sales forecasts and stipulated rates,
  - Depreciation and amortization is based upon accounting policy and expected capital projects/expenditures,

[3] Additional information from fact verification.

- Revenue-based PILOTs is based upon sales forecasts and stipulated rates,
- Property-based PILOTs is based upon historical experience, and
- Interest expense is based upon financing agreement and terms and maturity schedules.

- The PSA requires National Grid to annually submit a rolling five-year capital-improvement plan for LIPA's review. The first year of the plan is National Grid's proposed capital budget for the upcoming contract year, which requires LIPA's approval. The second through fifth years of the plan are for information only. National Grid normally presents its plan in October for the ensuing five-year period in the form of a spreadsheet that lists anticipated spending by individual project and year. The plan also includes a brief project-justification document for each new project in the upcoming year. Although the format of the document is not rigidly prescribed, it generally provides the following information: introduction and background; statement of problem; project description, scope, estimated costs and schedule; alternatives; and project benefits or consequences of inaction. Each project is classified by the principal reason for its being proposed. The classifications are: Legal or Regulatory Mandate; Safety; Reliability; Thermal Efficiency; and Other.[4]

- A limited amount of the budget is actually discretionary. Therefore, "zero-based budgeting" is not used.

11.3.2 LIPA's capital budgeting process is well documented, adhered to, and effective in establishing annual spending levels. However, the budgeting process concentrates on how much to spend and less on the value received.

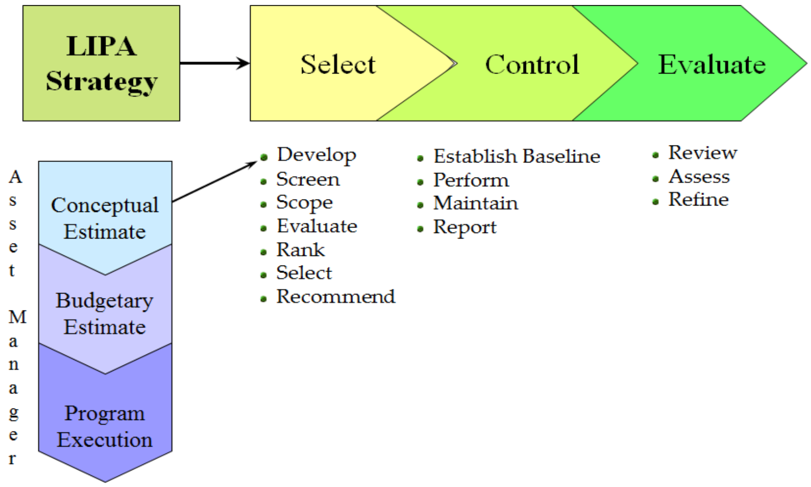
- Capital budgeting processes include assessment and estimation of future capital spending levels, identifying and selecting projects, calculating project conceptual to annual budget estimates (C to B for T&D projects), and the process for project completion and close-out.[5]

- LIPA's T&D capital planning process entails selection, control, and evaluation of proposed projects, as shown in **Exhibit 11-4**.[6]

- LIPA sets the level of capital spending, and makes the final selection of the projects. Under the MSA, National Grid proposes T&D capital projects, develops the project conceptual estimates, develops the annual budget estimates, and executes the capital program. Conceptual estimates are used to develop, screen, scope, and evaluate potential projects.

[4] Information provided in fact verification and DR 158
[5] DR 188
[6] DR 188

Exhibit 11-4
LIPA's T&D Capital Planning Process



- The T&D capital budgeting process consists of three major steps:

  - Establish a target funding level for projects
  - Select projects based on LIPA's expenditure prioritization methodology
  - Monitor and control actual versus budgeted spending

- The target funding level is determined by several factors. These factors include results from the T&D business model, a proprietary model developed and run by Navigant Consulting, which evaluates different scenarios to determine sensitivity of various strategies; LIPA's Financial Model, which assesses the level of funds available based on current revenues; and the Reliability Model, which attempts to determine the level of capital expenditure required for reliability. The funding level does not determine funding for individual projects; it establishes the aggregate funding available for all T&D capital projects.

- The identification, prioritization, and selection processes evaluate mandatory projects such as new customer connections, carryover or continuation projects, planning projects, upgrade and replacement programs, and discretionary projects - strategic investments in the T&D system. Mandatory and carryover projects are given a higher priority than new projects. The need for planning projects is based on "risk scoring," which considers the level of exposed load, hours of exposure, and probability of the event causing the exposure. The budgets for remaining projects are established using a sliding scale that reflects the expected impact of the expenditure.

- The target level of capital budget is derived from actual historical expenditures, estimates of future work, strategic future investments, and the target funding level, which is established using the T&D business model. Keeping forecasted budget levels in mind, National Grid meets internally to determine which projects will be recommended to LIPA as part of the proposed 2-year capital budget. National Grid must contractually submit a proposed capital budget to LIPA by June 30 of each year.

- A series of meetings to review the proposed capital budget are held between LIPA and National Grid during July and August. During these meetings, LIPA and National Grid discuss needs, alternatives, scopes, conceptual estimates and review project risk scores. As a result of the discussion, follow-up items are provided to National Grid for further review.

- National Grid refines approved capital project conceptual (C) to budget (B) cost estimates, based on engineering and field review after the budget has been approved, during the following year. A final project budget is approved to establish the annual spending level for all projects.

- Individual projects are completed, and project spending is reported in National Grid's monthly spending variance reports to LIPA.

11.3.3 T&D capital spending levels are analytically determined and are not based on project needs or project costs.

- LIPA's contractor, Navigant Consulting uses a proprietary T&D business model, an Excel-based tool, to evaluate different strategies that impact LIPA's T&D value creation during at a 10-year forecast window. It performs a statistical analysis of the various drivers by employing Palisade @Risk software. The outputs include Net Present Value (NPV) of Funds Available, T&D O&M Cost, T&D Capital Expenditure and Marginal Cost of future T&D projects by each load pocket. The model is updated annually in April, and is used to analyze capital spending levels.[7]

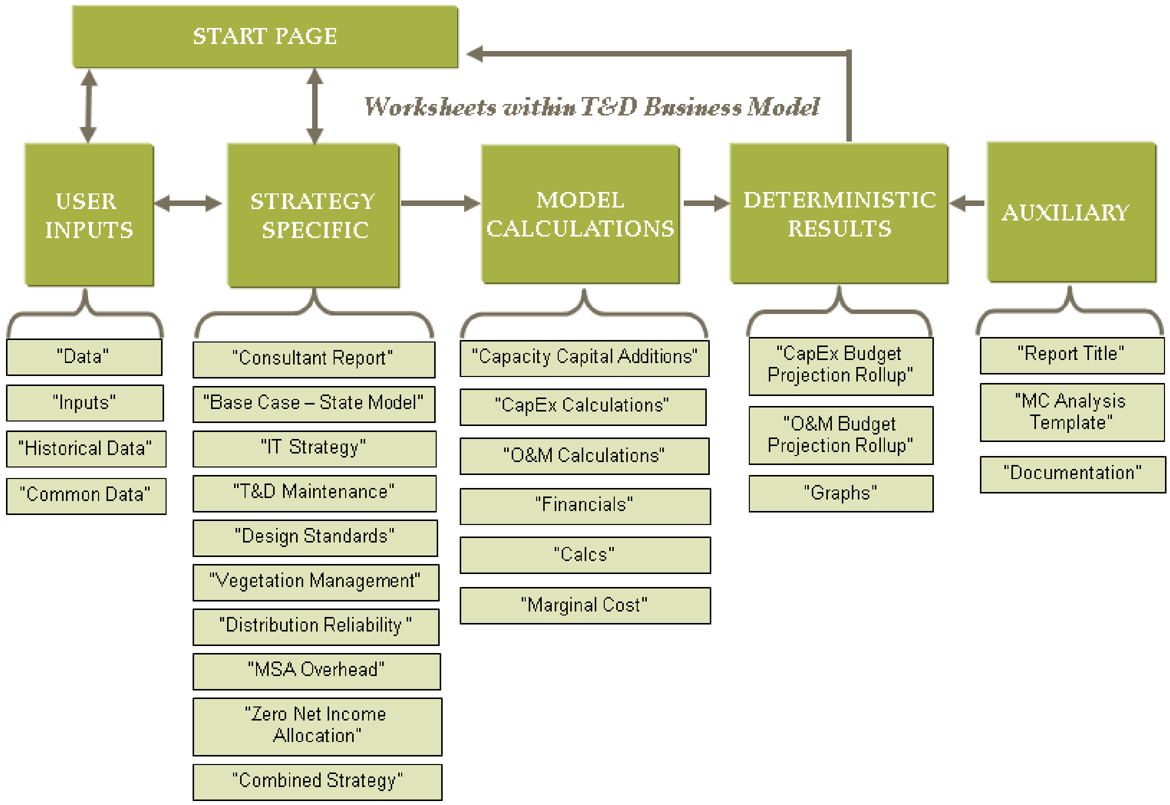
- The model allows for various strategies to be modeled, reflecting the sensitivities desired by the user. T&D value (NPV of Funds Available) is affected by implementing potential strategic alternatives. **Exhibit 11-5** summarizes the strategies that are currently available in the model.

- The model focuses only on LIPA's T&D business based on the following:

  - Treating LIPA T&D as a "stand alone" business entity
  - Explicit modeling of the MSA incentives, requirements, and constraints
  - Impacts of the Cost of Service study
  - Allocation of a portion of the total LIPA Net Income

[7] DR 188

Exhibit 11-5
T&D Value Strategies



11.3.4 T&D capital projects representing nearly $300 million are developed through an annual budget process.

- T&D projects are identified through planning studies, operational analyses, upgrades or programmed replacements to maintain or improve reliability as described in **Chapter 9 – System Planning**.

- There is a continuous need to implement programmed replacements to maintain or improve system reliability. These programmed replacements are multi-year and include programs such as:

  - Circuit improvement
  - Overhead distribution enhancements
  - Distribution and transmission pole replacements
  - Distribution transformers purchase and installation

- Programmed replacements are capital improvement projects aggregated due to their similarity and individually smaller cost. The programs (multiple capital projects) are therefore included in annual capital budget considerations.

- National Grid schedules meetings with all internal organizations to discuss the projects they are proposing for consideration during the next two years. Projects are estimated by National Grid's planning, engineering and construction functions based on their opinions of material and work hours. These estimates are based largely on planning, engineering and construction experience with similar projects completed in the past. These internal meetings are expected to be completed by May 15.

- National Grid develops risk scores and Project Justification Documents (PJDs) for each project. PJDs explain why each project is needed, the project's risk score, alternatives in some cases and consequences, expected time for implementation, and recommended solution. PJDs for the upcoming two years are submitted to LIPA with the proposed budget by June 30 of each year.

- National Grid determines which projects to recommend for inclusion in the LIPA budget. National Grid will also address constraints such as resource availability and the ability to physically meet the targeted dates.

- National Grid submits the T&D capital budget to LIPA for review by June 30 of each year and meetings to review the capital budget take place in July and August between LIPA and National Grid. The goal of the review meetings is to review proposed projects, discuss alternatives, review risk scores, and prioritize projects.

- These meetings conclude when LIPA's questions about the budget and projects are answered, and a final list of projects agreed to by LIPA and National Grid is developed. The capital budget is then reviewed by LIPA's BRC. The final capital budget is submitted to LIPA's Board of Trustees for approval during October.

- Following the LIPA Board of Trustees budget approval, National Grid refines the conceptual estimates with preliminary engineering and field reviews to develop the annual budgetary (spending level) estimates. Spending estimates are developed in the first few months of the budget year.

11.3.5 An objective scoring system is used to prioritize transmission and distribution capital projects.

- National Grid assigns each discretionary T&D capital project a risk score to provide guidance in the selection and prioritization of projects and programs in the capital budget. Risk scores are developed in conjunction with the creation of PJDs. Project risk scores are then reviewed by LIPA in July and August. Capital project prioritization and risk scoring is discussed in greater detail in **Chapter 9 – System Planning**.

    - The risk score is based on a combination of potential project impact and likelihood. Project impact is comprised of four categories, which include regulatory requirements, customer service requirements, financial performance, and technical performance.

- Likelihood refers to the risks associated with an equipment failure or malfunction event. This category considers the timeframe in which the event can occur, the likelihood of the event occurring, and how readily the event could be detected.
- The overall risk score of the project is calculated by multiplying the highest individual impact score for all categories and the likelihood of that particular impact occurring.

11.3.6 Estimates used for T&D capital budget approval are conceptual only, with no details. Project estimates are then refined for annual budget spending limits after the budget has been approved.

- Project estimates submitted by June 30 of each year for the annual budget process are estimated using conceptual scope, high level engineering, and limited field review. The estimates are considered conceptual in nature and are inherently inaccurate. The final list of approved projects within the approved budget then undergoes more detailed cost estimating (C to B estimates) to determine labor hours, materials, contractor costs and construction management burden to develop budget level estimates. Projects will be added or deferred as required to meet LIPA's approved budget level at National Grid's C to B meetings, which take place in mid-January of the then current budget year for submittal to LIPA in February.

- The goal of C to B meetings is to arrive at annual spending level estimates. When budget level estimates are considered, projects may have to be added or deferred in order to fit within LIPA's approved capital spending level. National Grid's Network Strategy Planning team and other sponsoring departments make these recommendations. National Grid's Program Management team reviews and develops the work plan and resource utilization based on B estimates. National Grid then submits the final capital program and budget level estimates for each project to LIPA's Vice President of Operations for approval.

11.3.7 The BOT reviews and approves only an overall level of capital spending. The Board does not review specific capital projects or programs.

- LIPA's capital project funding sources include internally generated funds (i.e., net revenues), bond financing, grants, and third-party contributions.[8] Capital expenditures not specifically funded with bond proceeds, grants, and third-party contributions, by default, are funded from internally generated funds.

- The capital budgets submitted to the Board of Trustees for consideration are summarized by function, i.e., Transmission, Distribution, Generation - Nine Mile Point 2, and General (LIPA). Within the Transmission and Distribution functions are broad sub-functions such as Transmission Interconnections - New Power Plants (Major Capital) and Substations (Major Capital).[9]

[8] DR 137 & 221
[9] DR 14

- The Board of Trustees does not approve specific capital projects, but instead, approves an overall level of funding for capital projects.[10]

- The proposed budget submitted to the Board of Trustees for consideration includes Statements of Sources and Uses of Funds that show planned borrowings over the next five years.[11]

- The Board of Trustees adopts an annual budget resolution approving a one-year expense budget, and a two-year capital budget. The budget resolution typically includes a "Declaration of Official Intent" specifying LIPA's intent to finance its capital budgets through a combination of internally generated funds and the issuance of tax-exempt or taxable debt.[12]

- At the same time, the Board adopts and approves the form of a supplemental bond resolution as required by LIPA's General Bond Resolution and/or General Subordinated Resolution (Bond Resolution). The Bond Resolution states the broad purpose and the level of borrowing, but does not identify the specific projects to be financed.[13]

11.3.8 A substantial portion of LIPA's expenses are contractual and/or non-discretionary in nature, and under the current operating structure LIPA lacks direct control over the bulk of its expenditures.

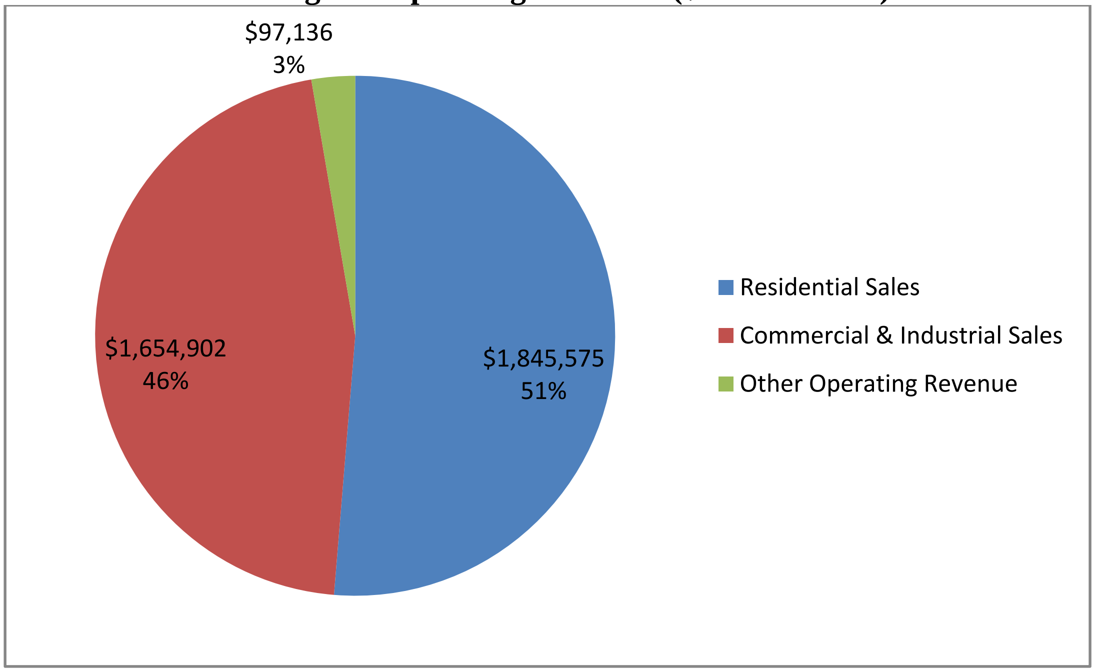
- LIPA's 2013 budgeted operating revenues total $3.6 billion and consists of electric sales to residential, commercial, and industrial customers; and other operating revenues (i.e., sales for resale, wheeling revenues, pole attachment fees, late payment and other miscellaneous charges), as shown in **Exhibit 11-6**.

- LIPA's 2013 budgeted expenses including a $75 million net income reserve ("Financial Reserve") totals approximately $3.6 billion, as shown in **Exhibit 11-7**.

- Approximately $3.5 billion or 95 percent of these above budgeted expenses are primarily contractual obligations and non-discretionary in nature (shown in **Exhibit 11-8**). The remaining $165 million or 5 percent includes Energy Efficiency & Renewables, Professional Services & General Expense, and Salaries & Benefits Expense categories that to some extent are discretionary. Given the fixed nature of LIPA's expenses, retail electric rates must be set at a level sufficient for full recovery of such costs.

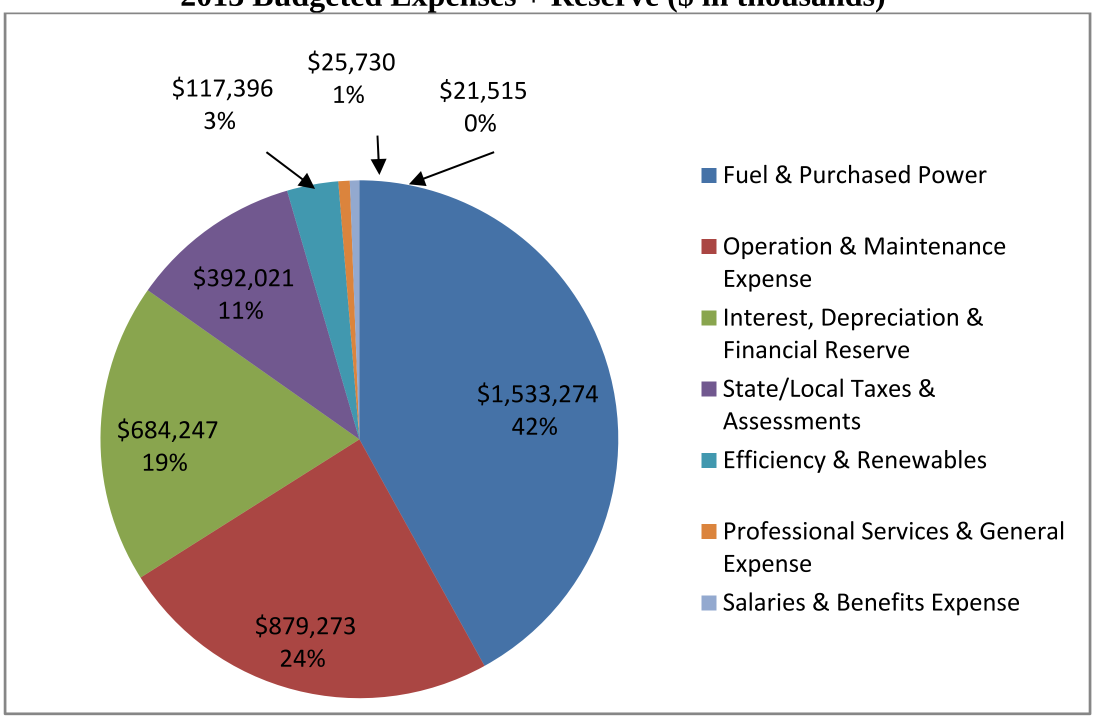
[10] DR 184
[11] DR 221
[12] DR 16 & 141
[13] DR 16

Exhibit 11-6
2013 Budgeted Operating Revenues ($ in thousands)



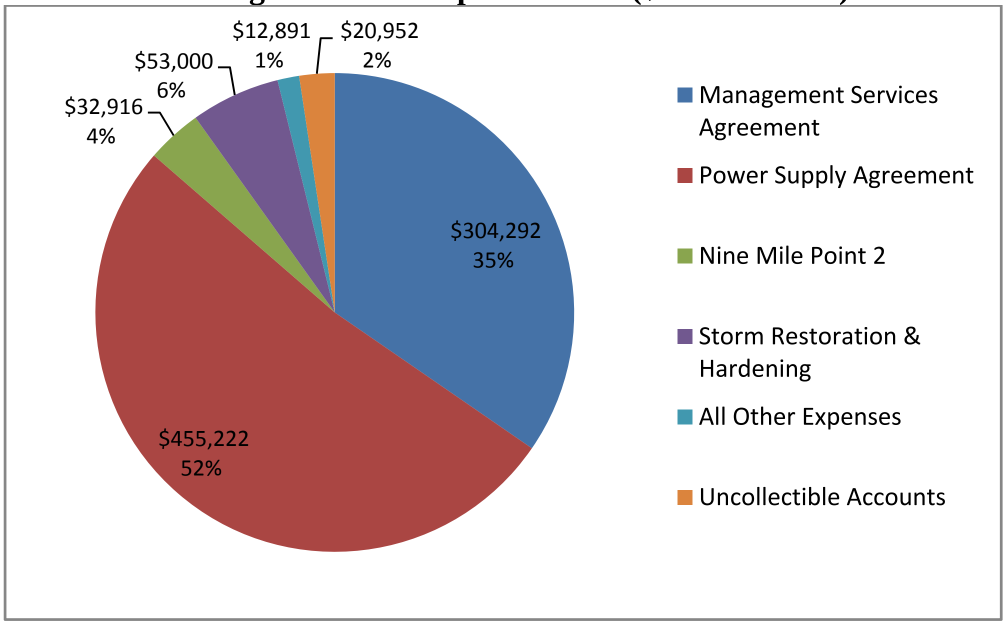
Source: DR 221

Exhibit 11-7
2013 Budgeted Expenses + Reserve ($ in thousands)



Source: DR 221
Note: Operation & Maintenance Expense shown in the above chart excludes Efficiency & Renewables, and Assessments for purposes of this analysis.

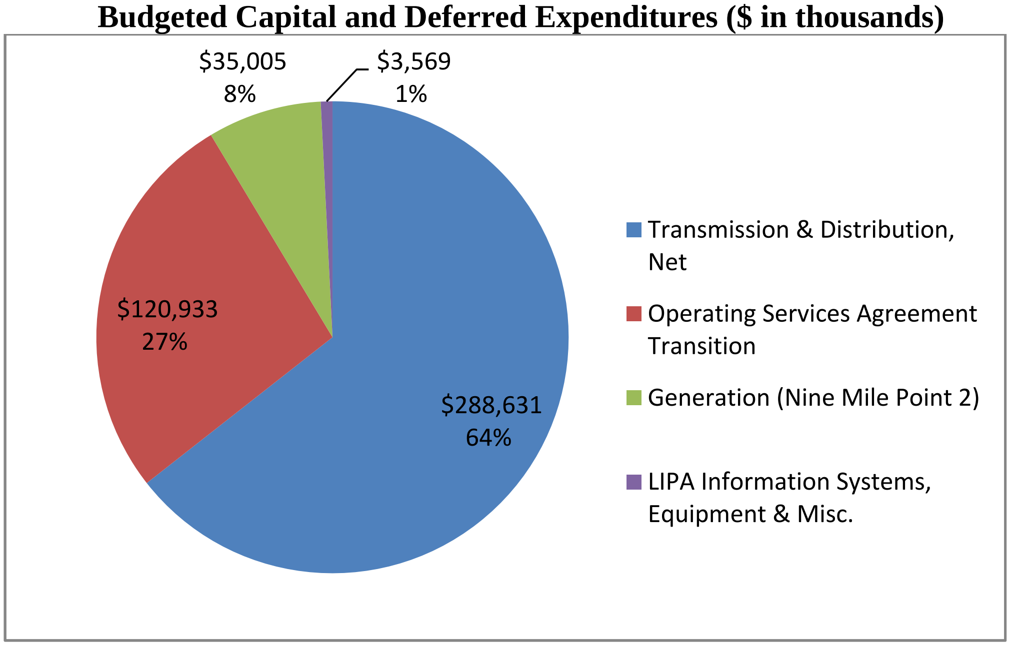
Exhibit 11-8
Budgeted O&M Expense Detail ($ in thousands)



Source: DR 221

- LIPA's 2013 budgeted capital and deferred expenditures total approximately $448 million as shown in **Exhibit 11-9**. LIPA does not have any planned borrowing projected in 2013.[14]

Exhibit 11-9
Budgeted Capital and Deferred Expenditures ($ in thousands)



Source: DR 221

[14] DR 221

- LIPA's T&D capital projects net of cost-sharing and other contributions account for approximately $289 million or 64 percent of the total capital program, or 88 percent if Operating Services Agreement Transition expenditures are excluded.[15]

11.3.9 LIPA's cash reserve policy is largely based on an arbitrary target, rather than being analytically justified.

- LIPA did not provide any formal analysis to justify its current cash reserve policy or of the potential impact that operational changes and uncertainties may have with respect to such policy (e.g., FPPCA restructuring, exposure to post collateral in connection with energy risk management financial hedges, or timing or size of FEMA storm reimbursements. In addition, no analysis was provided regarding the potential impact on cash reserve requirements of upcoming changes under the OSA (e.g., operating account pre-funding requirement, change from a fixed monthly O&M expense billing to a variable expense pass-through).[16]

- LIPA's cash reserve target is $400 million and consists of $250 million of operating cash and $150 million set aside in a Rate Stabilization Fund (RSF).

- The RSF is set forth in LIPA's Bond Resolution, and the minimum level of funding (i.e., $150 million) is required pursuant to Reimbursement Agreements with State Street Bank and Trust Company and JPMorgan Chase Bank, National Association for Sub-Series 1B and 3A subordinated revenue bonds, respectively.[17] The RSF's primary purpose is to provide liquidity to further support the specified variable rate bonds, but can be used for any lawful purpose. The minimum level of funding must be maintained, or if drawn down, replaced within a specified period of time (i.e., from 30 to 180 days depending on reason for the draw).

- From 2008 through 2012, LIPA cumulatively drew down the balance in its Rate Stabilization Fund by $106.8 million; $100.1 million of which occurred in 2011.[18] However, during this period the balance in the RSF did not fall below the minimum threshold of $150 million.

- LIPA's monthly cash flow projections for 2012 and 2013 are highly variable, as shown in **Exhibit 11-10**.

- LIPA's actual 2012 and 2013 monthly cash balance is shown in **Exhibit 11-11**. These figures includes the $250 million of bond proceeds in June 2012, but <u>excludes</u> the approximately $150 million on deposit in a Rate Stabilization Fund for 2012 and

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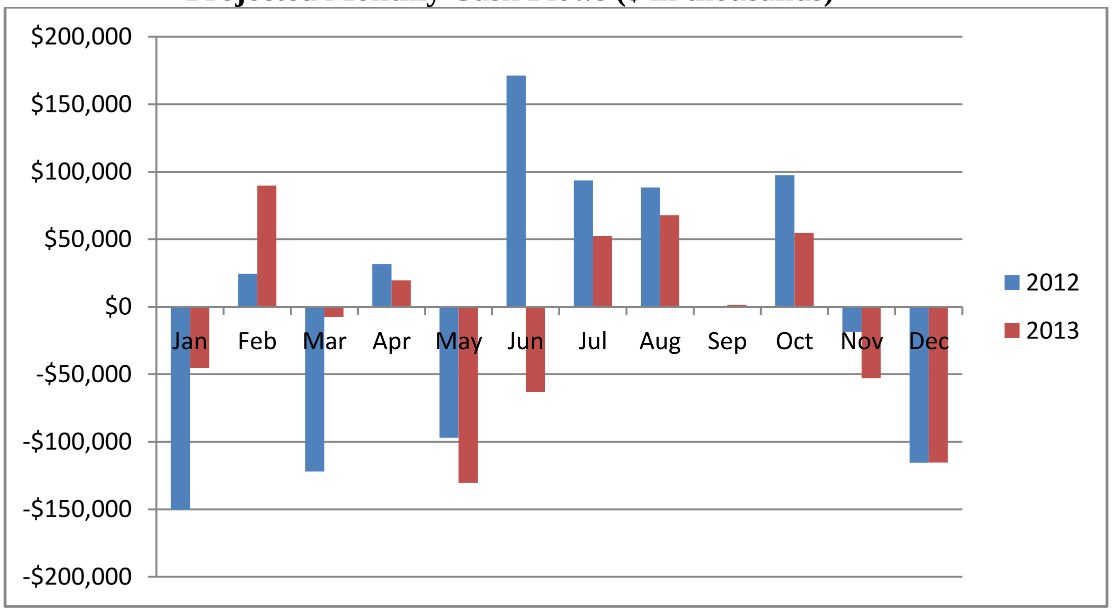
[15] DR 221
[16] DR 151, 223, 333 (No response to DR), 353, 403, & 896 (No response to DR)
[17] DR 596
[18] DR 404

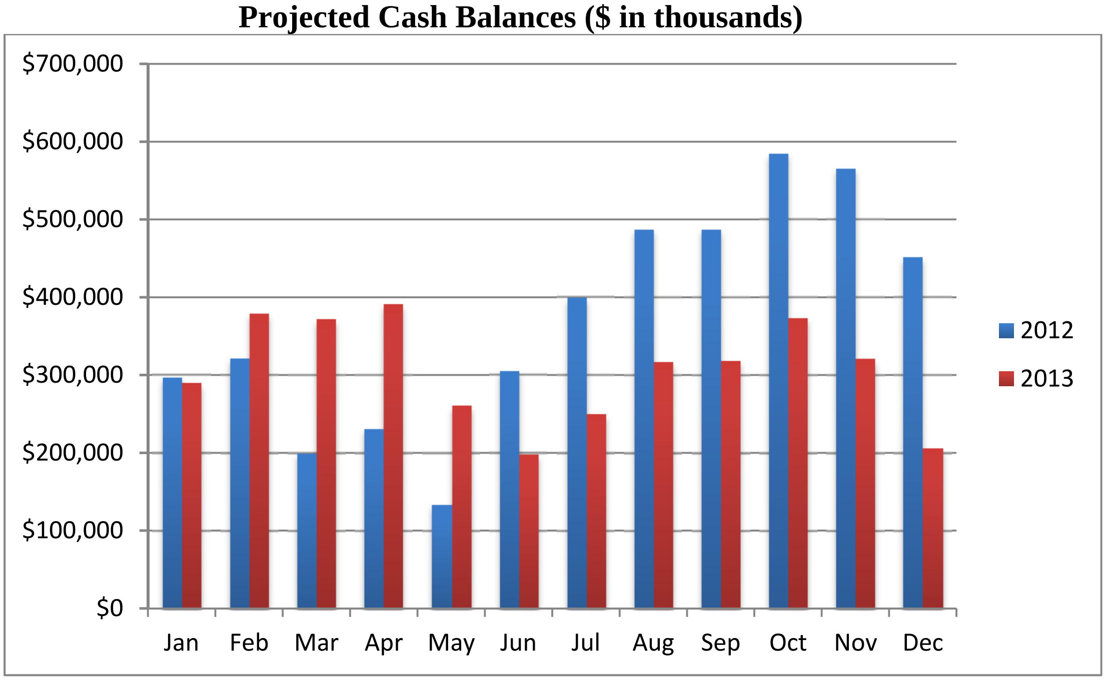
2013.[19] On average LIPA held $372 million of cash reserves in 2012 ($522 million including the RSF) and $307 million ($457 with the RSF) in 2013.

Exhibit 11-10
Projected Monthly Cash Flows ($ in thousands)[20]



Source: DR 328

Exhibit 11-11
Projected Cash Balances ($ in thousands)



Source: DR 328

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19 DR 897
20 Includes $250 million of bond proceeds in June 2012; no borrowing planned in 2013.

- In early 2013, LIPA secured a $500 million revolving line of credit to enhance working capital.[21] LIPA is working with its financial advisor and underwriting team to evaluate options to further enhance liquidity. Under consideration is the issuance of bonds or notes to refund all or a portion of its outstanding commercial paper program (i.e., $300 million authorized and $200 million outstanding), and establish a new program to increase liquidity; and issuing medium-term notes, as needed, to bridge finance all or a portion of Hurricane Sandy storm restoration costs that are subject to FEMA reimbursement.[22]

- LIPA restructured its Fuel and Purchased Power Cost Adjustment (FPPCA) effective in early 2013 to eliminate a $50 million net income dead band, change the frequency of calculation from quarterly to monthly, and eliminate the cost smoothing mechanism. These actions will serve to better align its FPPCA revenues and expenses, and improve liquidity.[23]

- On May 15, 2013, Moody's Investors Service (Moody's) downgraded LIPA's bonds by one notch, with a negative rating outlook. Moody's cited persistently weak credit metrics and "little if any cushion for unforeseen events that seem to occur every year". The downgrade takes into account the liquidity provided by the new $500 million credit facility, but raises concerns regarding the amount, timing, and predictability of FEMA reimbursements for Hurricane Sandy costs, and the need to pre-fund the OSA operating account.[24]

11.3.10 LIPA's dependency on FEMA for major storm cost reimbursement is tenuous.

- LIPA budgets for storm restoration costs associated with non-FEMA storm events.[25] LIPA has established a $15 million "Storm Reserve" to pay for "Storm Events" as set forth under Section 6.4 of the Amended and Restated MSA dated January 1, 2006.[26.]

- LIPA does not budget for storm restoration costs that are subject, in part, to FEMA reimbursement, due to the infrequent and unpredictable nature of such storm events.[27] Lack of a budget or reserve to pay for major storm restoration costs places a heavy financial burden on LIPA and a greater dependency on FEMA.

- LIPA's initial estimate of Hurricane Sandy restoration costs totaled approximately $806 million. LIPA expects to receive reimbursement from FEMA for at least 75 percent or $605 million of the eligible costs related to restoration work. LIPA believes that

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[21] DR 14
[22] DR 13, 334 & 335
[23] DR 220 & 353
[24] Moody's Investor's Service - Ratings Action Dated May 15, 2013
[25] DR 184 & 287
[26] DR 4
[27] DR 287

damage to the State will exceed a federally mandated per capita level, and therefore, the cost reimbursement may increase from 75 percent to 90 percent.[28]

11.3.11 LIPA's financing considerations are appropriately incorporated into the capital and O&M budgeting and financial forecasting process.

- LIPA's decision to issue bonds to fund its capital improvement program is integrated with the annual budgeting process, and establishment of five-year projections of revenues and expenses, and cash flows.[29]

- The annual budget submitted annually to the Board of Trustees in December includes five-year projected Statements of Revenues and Expenses showing debt service coverage, and Statements of Sources and Uses of Funds showing planned borrowings and debt service. A listing of outstanding debt and a calculation to support projected interest expense is also provided for the budget year.[30]

11.3.12 Based on the information provided by LIPA, it cannot be determined if LIPA has fully complied with regulations regarding tax-advantaged bonds, including documentation supporting the reimbursement of capital projects from bond proceeds.

- LIPA did not provide formal policies and procedures with respect to the allocation of tax-exempt bond proceeds to capital projects.[31] On August 14, 2012, LIPA's CFO adopted Interim Post-Issuance Tax Compliance Policies and Procedures for maintaining compliance with provisions of the Internal Revenue Code regarding tax-advantaged bonds and notes (i.e., tax-exempt and Build America tax-credit bonds). Section 1, Scope and Purpose, specifies that Bond Counsel advised LIPA that "adoption of formal written policies and procedures is strongly recommended by the IRS with respect to arbitrage rebate and yield restriction, monitoring of bond-financed facilities for private activity compliance, accounting and recordkeeping, and tax documentation and filing requirements"; and the Interim Post-Issuance Policies and Procedures will be submitted to the Board of Trustees Finance and Audit Committee for ratification, approval, and finalization.[32] LIPA did not provide documentation to support the Finance and Audit Committee's consideration and adoption of the Interim Post-Issuance Policies and Procedures.

- LIPA is required per the Interim Post-Issuance Policies and Procedures to maintain documentation evidencing the expenditure of proceeds from each bond issue, including invoices, payment records, actual capital costs, and project details for a period of six years after the last obligation of each bond issue has been retired.[33]

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[28] Long Island Power Authority, Basic Financial Statements, December 31, 2012 and 2011
[29] DR 14 & 137
[30] DR 14
[31] DR 892 - No response
[32] DR 130
[33] DR 130

- Proceeds from the issuance of bonds are required by the Bond Resolution to be deposited into the Authority's Construction Fund. LIPA's external investment manager invests proceeds from the issuance of bonds on deposit in the Construction Fund based on investment guidelines provided by LIPA. The investment guidelines do not provide guidance with respect to the investment of tax-exempt bond proceeds.[34] Tax-exempt bond proceeds can be yield restricted and subject to arbitrage rebate requirements set forth in the Internal Revenue Code.

- LIPA's bond counsel notes that "the Tax Certificates also provide guidance regarding investments, although with very few exceptions has LIPA qualified for rebate exceptions and LIPA has not had a material amount of funds other than escrow funds for refunded bonds that were subject to yield restriction."[35]

- LIPA and its Bond Counsel jointly review capital project expenditures and determine which expenditures qualify for payment or reimbursement from bond proceeds. LIPA uses a specific tracing method to make a final allocation of the bond proceeds to capital projects.[36] However, LIPA was not able to provide documentation to support the final use or allocation of tax-exempt bond proceeds for its two most recent bond issues (i.e., 2012A & 2011A Electric System General Revenue Bonds) as they have not been completed.[37]

- LIPA reports that it is not aware of any debt covenant violations except for power purchase agreements that were entered into in the early 2000's. These agreements were classified as capital leases and had principal payments that exceeded a $25 million cap specified in Section 6.7 of the Reimbursement Agreement related to Series 1 through 3 bonds dated May 1, 2003. The Authority sought and obtained waivers from the affected lending institutions.[38]

- On November 10, 2011, the Internal Revenue Service (IRS) initiated an examination of LIPA's $950,000,000 Electric System General Revenue Bonds, Series 2006A and Series 2006B, Issued on March 21, 2006. The 2006A bonds were advance refunding bonds in the amount of $853,045,000, the proceeds of which were deposited in a dedicated defeasance account by the Escrow Agent (i.e., Bank of New York) and were yield restricted. During the course of gathering the information requested by the IRS, LIPA discovered that the Escrow Agent had not fully complied with the applicable escrow agreement, and as a result, the yield on the defeasance escrow was slightly higher than the permitted yield. The Escrow Agent agreed to reimburse LIPA, and the ratepayer incurs no costs related to this issue. On June 26, 2013, LIPA remitted $81,365.82 to the IRS that consisted of an arbitrage rebate payment, yield reduction payment, and interest. The matter is pending a final determination by the IRS.[39]

[34] DR 130
[35] DR 216
[36] DR 130 & 332
[37] DR 217, 597, & 893(No response)
[38] DR 197
[39] DR 218 & 814

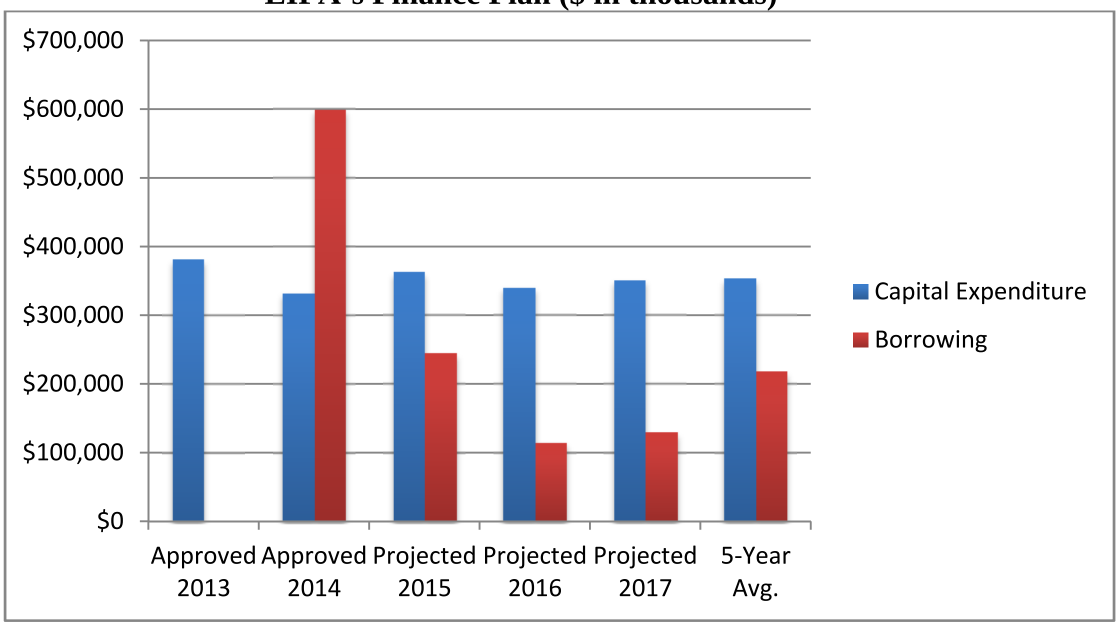
- LIPA recently established its internal audit function, and a formal policy has not been established with respect to audits of debt management activities. No prior internal audits of debt management activities have been conducted by LIPA.[40]

11.3.13 LIPA's projected mix of bond financing and pay-as-you-go funding of its capital program is balanced.

- LIPA has financed its capital program through a combination of proceeds from borrowing, funding from internally generated funds, and to a lesser extent, grant or third-party funding.[41]

- LIPA's projected capital improvement program for 2013 through 2017 averages approximately $354 million. LIPA plans to borrow an average of $218 million or 62 percent over the next five years, as shown in **Exhibit 11-12**. The remaining capital project funding will come from internally generated funds. This level of internal funding ($136 million) is consistent with past internal funding levels.

Exhibit 11-12
LIPA's Finance Plan ($ in thousands)

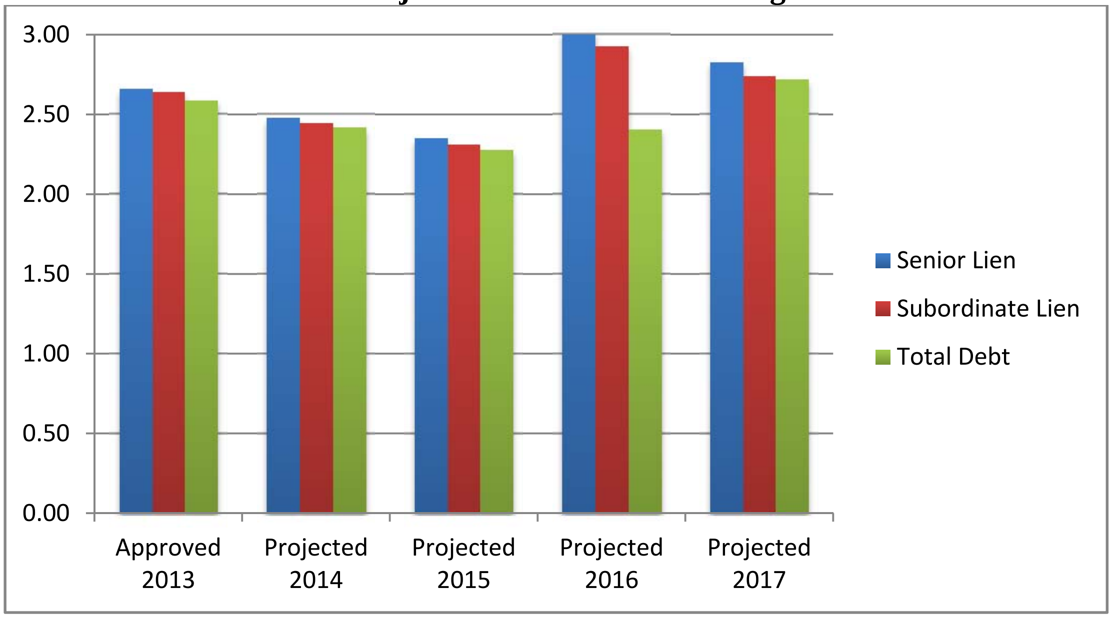


Source: DR 14

- LIPA's projected debt service coverage ratios for the period 2013 through 2017 exceed the minimum 1.0 times coverage set forth in the Bond Resolution, as shown in **Exhibit 11-13**.

[40] DR 143 & 748
[41] DR 14

Exhibit 11-13
LIPA's Projected Debt Service Coverage



Source: DR 14
Note: LIPA expects to refund and modify the term of certain bonds that mature in 2014 and 2015. Should this occur, debt service coverages in 2014 and 2015 will improve.

- LIPA's debt service coverage ratios calculated in accordance with the priority of payments set forth in its Bond Resolution exclude capital lease expenses and PILOTS from the denominator. The debt service coverage ratios calculated by the rating agencies include such expenses in the denominator, and therefore are lower.

11.3.14 LIPA's budget process tends to focus on the short-term objective of mitigating or eliminating the need for revenue increases.

- LIPA's budget process includes a preliminary review of the proposed budget and Statement of Revenues and Expenses by the BRC. The BRC assesses the impact of the preliminary budget on retail rates.

- LIPA's process for determining the level of aggregate funding available for 2013 T&D capital expenditures includes a strategy that assumes zero net income is allocated to T&D capital expenditures and revenues are capped at 2012 cost of service.[42]

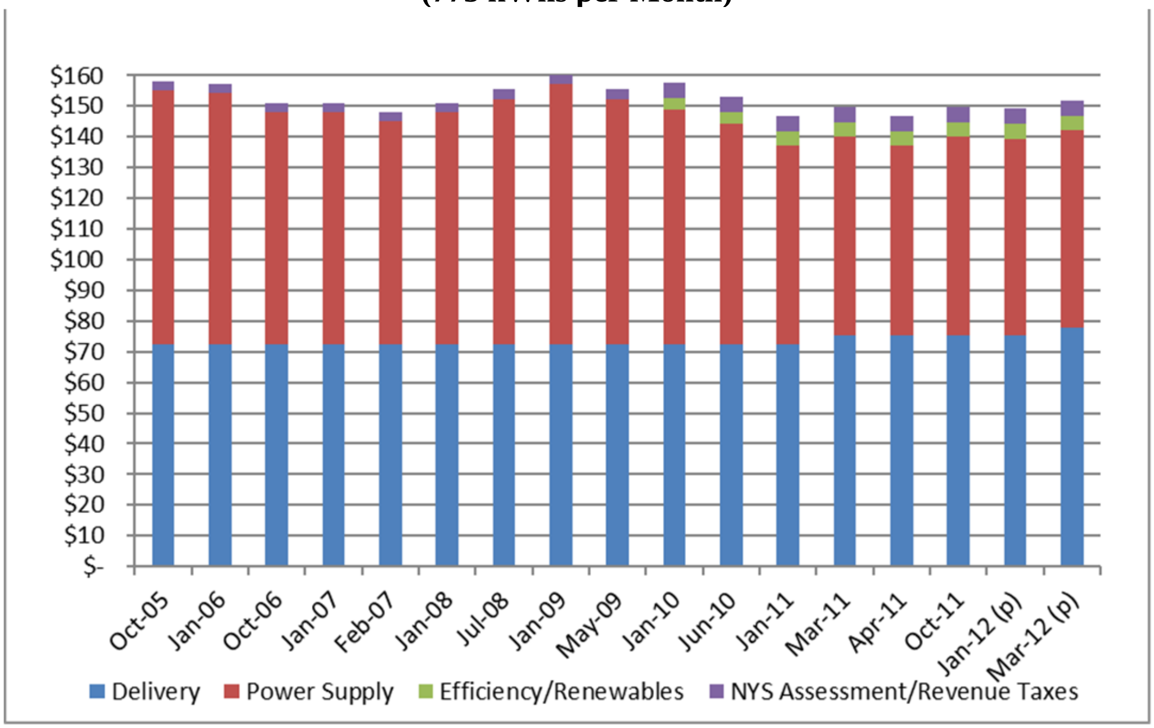
- LIPA's 5-year Projected Statements of Revenues and Expenses included in the annual budget materials submitted to the Board of Trustees include planned revenue increases for years 2 through 5 embedded in revenues. The amounts and percentage increases, however, are not shown separately.[43]

[42] DR 337
[43] DR 599

- The Board of Trustees Finance and Audit Committee reviews and makes recommendations on management's rate proposals to the Board of Trustees. Although not required, LIPA typically conducts public input sessions to solicit input from the public on rate proposals.[44]

- LIPA has increased its residential Delivery Charge rate component twice over the past 14 years: 4.1 percent and 3.4 percent in March 2011 and 2012, respectively.[45] Notwithstanding such increases, LIPA's typical monthly residential electric bill (i.e., 775 kWhs) has been relatively flat during the past seven years, as shown in **Exhibit 11-14**.

Exhibit 11-14
Trend in Typical Residential Bill
(775 kWhs per Month)



Source: DR 195

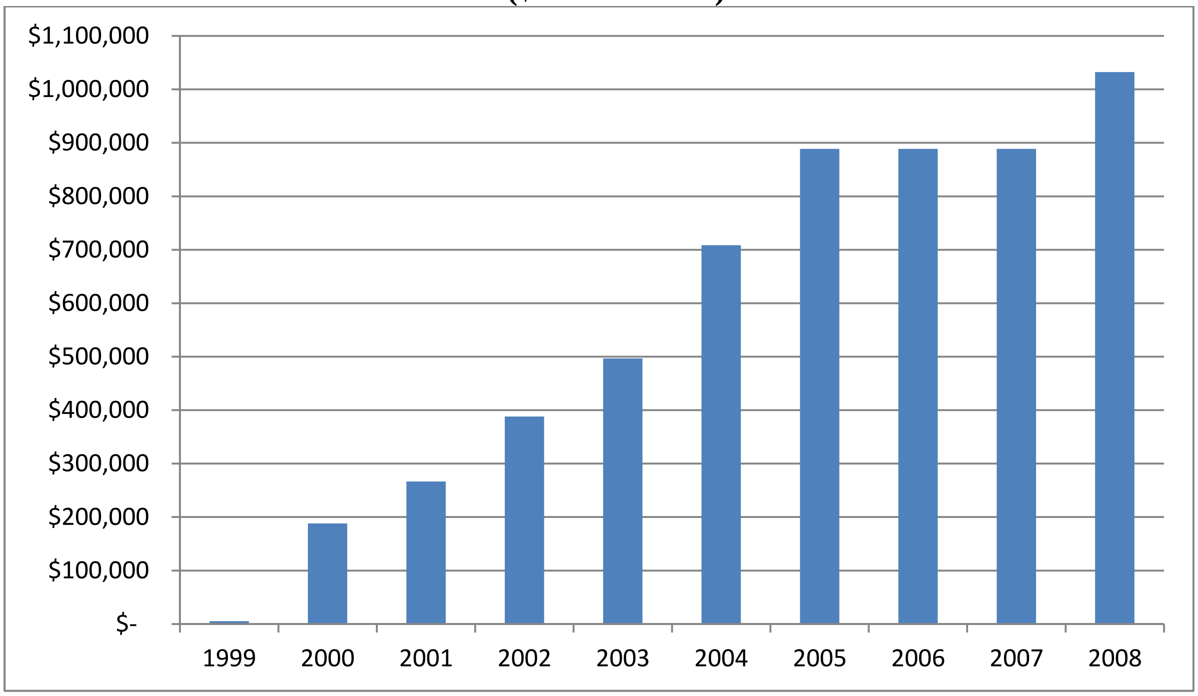
- LIPA has implemented an energy risk management program designed to mitigate the financial impact of volatile fuel and purchased power costs on customer bills, as discussed in **Chapter 18 – Power Supply and Fuel Management**.[46]

- LIPA has absorbed approximately $1.032 billion of fuel costs due to a combination of prior constraints set forth in Tariff Leaf 166 with respect to the operation of the Fuel and Purchased Power Cost Adjustment, or Board of Trustees decisions to recover such costs in the "headroom" that existed in LIPA's initial retail rates or forego recovery, as

[44] DR 195
[45] DR 112 & 195
[46] DR 224

shown in **Exhibit 11-15**. Any recovery of such absorbed fuel and purchased power costs would have increased the need for a revenue increase, but reduced the need for borrowing.

Exhibit 11-15
Cumulative Absorbed Fuel & Purchased Power Costs
($ in thousands)



Source: DR 243

11.3.15 A variety of analytical tools including financial modeling techniques are used in the LIPA budgeting process. LIPA's financial models have served them well, but do not produce proforma balance sheets.

- LIPA uses Microsoft Excel (Excel) models for compiling budgets, and for developing financial forecasts. The LIPA's financial forecasting function is outsourced. LIPA uses Excel templates to develop and consolidate its departmental (e.g., Finance and Government Relations) budgets. Departmental budgets are combined with non-departmental (e.g., revenue forecast, capital expenditures, and T&D O&M) components of its budgets into an Excel-based master budget model that is used to prepare a Statement of Revenues and Expenses (i.e., Income Statement) for the first year of the budget.[47]

- Navigant provides financial support services to LIPA, the scope of which includes preparation of long-term budget and financial projections.[48] Navigant uses an Excel-based financial model to develop projected Income Statements for years 2 through 5 and Statements of Sources and Uses of Funds (i.e., Statements of Cash Flow) for years

[47] DR 184
[48] DR 234

1 through 5, based, in part, on input provided by LIPA, including the Income Statement for the first year.

- Financial reports produced by the aforementioned financial model(s) do not include projected Statements of Net Position (i.e., Balance Sheets). Balance Sheets and Income Statements are typically used to prepare the Statements of Cash Flow and ensure that the financial statements reconcile. Balance Sheets may also be useful for ratio analysis such as liquidity (i.e., working capital) and leverage (i.e., debt-to-equity).

11.3.16 LIPA's process for issuing tax-exempt bonds to fund capital projects is appropriate and typical of other major public utilities.

- LIPA's decision to issue bonds to fund a portion of its capital improvement program is integrated with the annual budgeting process, and establishment of five-year projections of revenues and expenses and cash flows.[49]

- Sources of funding for capital improvements are determined in the context of the entire budget process that takes into account the availability of internally generated funds, bond financings, grants, and third-party contributions. The availability of internally generated funds is determined based on LIPA's capital expenditure program requirements and operating plan. The operating plan takes into account projected revenues and expenditures: a $75 million net income target, a $400 cash reserve requirement, and projected debt service coverages. Any remaining shortfall in capital improvement program funding is financed with bond proceeds.[50]

- LIPA's Debt Management Policy sets forth the parameters for issuing and managing outstanding debt. It provides guidance regarding required authorizations for debt issuance, purposes for which debt may be issued, timing and methods of sale, debt structure, and use of derivative instruments.[51]

- LIPA retains a Financial Advisor to supplement in-house expertise and provide assistance on all financial matters, including the sale of bonds (e.g., pricing assistance), use of derivative instruments, and management of debt and credit ratings.[52]

- LIPA maintains a pool of underwriters selected through a competitive Request for Proposals process to serve as Senior Managers, Co-Managers, and a Selling Group in an effort to minimize the cost of bonds sold on a negotiated basis.[53]

- LIPA retains an external bond counsel and disclosure counsel. The bond counsel renders an opinion on the validity of bond offerings, and whether and to what extent interest on the bonds is exempt from income or other taxation. The disclosure counsel

[49] DR 137
[50] DR 137
[51] DR 137
[52] DR 137
[53] DR 137

renders an opinion and provides assurance to the underwriters and investors that disclosures being made by LIPA are fair and accurate.[54]

11.3.17 The Board of Trustees authorizes all financing transactions, and through its F&A Committee, effectively monitors LIPA's debt management practices.

- LIPA's Debt Management Policy specifies that all debt issues require explicit authorization by the Board of Trustees. For each bond issue, a supplemental resolution to LIPA's Bond Resolution is adopted describing the proposed debt and its purpose.[55]

- LIPA is required by the LIPA Act and other provisions of the Public Authorities Law (PAL) to obtain approval to issue bonds by the New York State Public Authorities Control Board (PACB). PACB staff requires a memo summarizing the requested authorization, use of proceeds, proposed structure, a draft PACB resolution, the resolution approved by the Board of Trustees, and other relevant information. The PACB must make certain determinations, including the financial feasibility of the financing and impact on customer rates, and approve the issuance by a unanimous vote.[56]

- LIPA is also required to obtain approval from the Office of the State Comptroller (OSC) for any private sale of debt pursuant to PAL Section 1020-k (4). The OSC has established a "Debt Issuance Approval Policy Statement and Guidelines" (Guidelines). LIPA's Debt Management Policy specifies that it will comply with the OSC Guidelines for all debt issuances, including the use of interest rate derivative products, and will submit all debt related contracts to the OSC for approval.[57]

- The Board of Trustees Finance and Audit Committee Charter states that it must meet prior to any debt issuance planned to be undertaken by the Authority. The F&A Committee is responsible for reviewing and approving proposals for the issuance of debt by LIPA, and making recommendations concerning such proposals to the Board of Trustees.[58]

- The proposed budget submitted to the Board of Trustees for consideration in December of each year, includes a detailed summary of interest expense and cost of debt for each issue, and five-year projected Statements of Sources and Uses of Funds that include planned financings.[59]

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[54] DR 137
[55] DR 14 & 137
[56] DR 137 & 140
[57] DR 137
[58] DR 30
[59] DR 195

11.4 Recommendations

11.4.1 Conduct a detailed review of proposed capital projects and expenditures with the BOT as part of the capital budget approval process. Provide actual capital expenditure updates to the BOT on project- and program-specific bases.

11.4.2 Conduct a formal analysis to determine the appropriate level of cash reserves, that at a minimum, considers potential changes in cash requirements due to the restructuring of the recent FPPCA, pre-funding requirement related to the OSA operating account, exposure to post collateral in connection with energy risk management financial hedging activities, transition from the MSA fixed O&M expenses billed on a predetermined monthly percentage to a variable expense pass-through by PSEG-LI to LIPA and that addresses the FEMA reimbursement impacts.

11.4.3 Develop and adopt formal set of policies and procedures for maintaining compliance with provisions of the Internal Revenue Code regarding tax-advantaged bonds and notes, including the process for reimbursing capital projects with bond proceeds.

11.4.4 Update the Investment Guidelines provided to LIPA's Investment Manager(s) to include instructions for investing proceeds from tax-advantaged bonds as it relates to potential Internal Revenue Code arbitrage yield restrictions and rebate requirements.

11.4.5 Perform an internal audit of debt management activities to ensure compliance with bond covenants and provisions of the Internal Revenue Code pertaining to tax-advantaged bonds.

11.4.6 Make revenue increases embedded in LIPA's proposed five-year Statements of Revenues and Expenses transparent to the Board of Trustees and Public during the annual budgeting cycle.

11.4.7 Enhance LIPA's internal financial planning capability and software tools and transition the long-term financial planning function from Navigant to LIPA.

12. T&D OPERATIONS AND MAINTENANCE

This chapter covers the T&D system operations, preventive and corrective maintenance practices, and oversight of the operations by LIPA.

12.1 Background

LIPA's transmission and sub-transmission lines deliver power to its electric system for 1.1 million customers in Nassau and Suffolk counties and the Rockaway Peninsula in Queens County. As defined by the NYISO, "bulk" transmission includes LIPA's 345 kV and 138 kV systems. LIPA's sub-transmission includes the 69 kV, 33 kV and 23 kV systems. Each system has circuits constructed overhead, underground and underwater. In addition, LIPA's electric T&D system has five standard alternating current (AC) and two High Voltage Direct Current (HVDC) interconnections to neighboring electric systems. The two 345 kV interconnections are used mainly to import power from the remainder of New York State to serve load requirements of LIPA, NYPA and Long Island municipalities. In addition, 286 MW of power is wheeled to ConEdison's Jamaica substation over the jointly owned Shore Road – Dunwoodie (Y50) interconnection.

The transmission system and the sub-transmission system serve distribution substations. Distribution substations are served from the 138, 69, 34 and 23 kv systems. In general, the sub-transmission system transfers power from the bulk transmission system to the various distribution substations, which typically serve approximately 10,000 customers per station. It also provides connection points to local 69 kV generation resources. In general, the sub-transmission system is designed in a closed loop arrangement originating from transmission substations that supply one or more distribution substations. Supervisory controlled circuit breakers and air break switches isolate faulted lines and restore service within a matter of seconds. The breakers at each end of a line may be line breakers, bus tie breakers, or part of ring bus, or breaker and half substation bus configurations.

Distribution circuits originate at circuit breakers connected to the distribution substations in the system. The circuits are made up of main line conductors connected in an open loop arrangement to one or more adjacent circuits and branch line conductors that are connected to the main lines through fuses. The circuit mains have various sectionalizing devices to isolate faulted conductors and to facilitate the transfer of customers to adjacent circuits. These devices include, automatic sectionalizing units, automatic circuit reclosers, ground operated load break switches and stick operated load break disconnects. The primary circuit mains are generally designed to operate as part of a radial system but in specific instances, where a higher degree of reliability is desired; they are designed for automatic throw-over or network operation. Primary lines that branch off the mains are equipped with fuses at the point of connection to keep the mains in operation when branch line faults occur.

LIPA has two types of low voltage secondary network service. Area networks are supplied from two or more dedicated primary circuits with no other distribution load connected. Spot networks are normally supplied from two or more primary circuits that also supply other distribution load. The chart below provides an overview of the system.

Queens/Nassau Serves approximately 210,512 customers 109 square miles of service territory, 1,035 miles of overhead wire 288 miles of underground cable 75,158 utility poles	**Central** Serves approximately 290,018 customers 210 square miles of service territory 2,374 miles of overhead wire 667 miles of underground cable 145,389 utility poles
Western Suffolk Serves approximately 320,839 Customers 305 square miles of service territory 2,718 miles of overhead wire 1,486 miles of underground cable 152,644 utility poles	**Eastern Suffolk** Serves approximately 289,484 customers 606 square miles of service territory 2,823 miles of overhead wire 2,220 miles of underground cable 161,859 utility poles

System reliability can be affected by many things including the following:

- Limited maintenance program funding and staffing, including vegetation management.
- Maintenance that is largely corrective upon failure, rather than preventive.
- Staffing levels that are unable to keep up with maintenance needs and recordkeeping.
- Poor or inadequate management, organization, leadership and work processes.

Preventive maintenance is commonly described as maintenance of equipment or systems before a fault or breakdown occurs. Preventive maintenance usually can be divided into two subgroups:

- Planned Maintenance
- Condition-based Maintenance

Planned Maintenance refers to any variety of scheduled work done on a system or piece of equipment that is intended to avoid any unscheduled outage or breakdown. Condition-based maintenance is work that is done when the need arises, based on one or more indicators that show that equipment is going to fail or that equipment performance is deteriorating. The main difference between these two subgroups is the determination of when the maintenance should be performed.

In spite of preventive maintenance all T&D equipment can fail and has some predefined life expectancy or operational life. T&D system equipment and components have life expectancies that vary considerably. For example, overhead lines and underground cable may last 50 years or more, while other equipment, such as switchgear, may be designed to operate at full design load for a set number of hours or start and stop cycles. The design life of most equipment is dependent upon periodic maintenance to ensure the equipment reaches or exceeds its design life.

Depending upon the criticality of the particular piece of equipment, and the availability of backup units, one option would be to wait for a piece of equipment to fail. As overall system reliability is a primary objective, in some cases a repair versus replace decision must be made before the equipment is allowed to fail. Effective repair or replace decisions require reliable and timely information, as well as a process that uses that information. The objective is to repair the equipment when the repair is more cost-effective than replacing it.

12.2 Evaluative Criteria

- Does LIPA/National Grid make effective use of mobile workforce tools?
- Does LIPA appropriately monitor and respond to potential reliability issues?
- Does LIPA/National Grid analyze worst performing circuits and take steps to address issues?
- Is preventive maintenance properly scheduled, performed and noted?
- Do managers have necessary and timely information?
- Does the organizational design effectively and efficiently support the mission?
- Are facility records (including specifications, location, maintenance, repair, and trouble history) comprehensive, accurate, up-to-date, and easily accessible?
- Are preventive maintenance goals and budgets reasonable?
- Is routine and as-needed maintenance performed on the system (including circuits and other equipment) as appropriate to mitigate potential issues?
- Are LIPA/National Grid's equipment inspection and testing schedules consistent with accepted good utility industry practice?
- Has LIPA/National Grid incorporated up-to-date processes and tools for monitoring, analyzing and maintaining its electric system?
- Are vegetation management cycles and standards consistent with industry practice and appropriate for the service territories?
- Are annual vegetation management goals and objectives met?
- Is LIPA appropriately involved in establishing preventive maintenance standards and requirements?
- Does LIPA have an appropriate system and set of metrics to determine the effectiveness of its preventive maintenance program and the effect of any changes to procedures or timelines?
- Are adequate cost/benefit analyses performed to assist in the repair/replace decision-making?
- Are work processes efficiently designed and implemented?
- Are LIPA/National Grid's assumptions regarding the life expectancy of key equipment reasonable?
- Is the extent of the use of "run to fail" method, and "life cycle" versus "fit for service" maintenance, rehabilitation and replacement practice appropriate?
- Has LIPA given adequate consideration to underground placement of conductors, circuits and distribution lines in key areas?

12.3 Findings and Conclusions

12.3.1 LIPA's participation in T&D operations and maintenance is minimal given its contract oversight role.

- LIPA does not perform system operations and maintenance. National Grid manages the T&D system under the MSA.[1]

  - National Grid provides operation and maintenance services and construction work for the T&D system on behalf of LIPA.[2]
  - National Grid's activities are comprehensive and with respect to T&D, include day-to-day operation, maintenance, repairs, engineering, standards, system performance, equipment ratings, pole attachments, joint use agreements, fleet, telecommunications, materials and services procurement, warehousing, and security. Responsibilities also include preparation of the recommended capital plan and budget, and delivery of a proposed annual operating and maintenance work plan.

- The MSA provides LIPA limited opportunities or obligations to participate in system operations and maintenance.

  - National Grid monitors and reports performance to LIPA each month under the various operational performance metrics contained in MSA Appendix 5.[3]
  - As the owner of the T&D system, LIPA retains ultimate authority and control over the assets and operations, but generally this is at a very high level and includes rates and charges, system policies and procedures, service rules, budget approval, legal, operational oversight and issues involving T&D assets, and financial matters.[4]
  - LIPA has the right to oversee and audit National Grid's operations performance. However, the agreement lacks specific standards of practice against which an audit would be performed.[5]

- LIPA pays National Grid a fee for the MSA operations and maintenance services with potential penalties if performance metrics fall below set levels.[6] In addition to the operations and maintenance fee, LIPA pays "pass-through expenditures" for a number of major items such as capital costs, claims and litigation, storm events, taxes, refunds, third-party conservation, and repair for any damage to submerged marine cable.

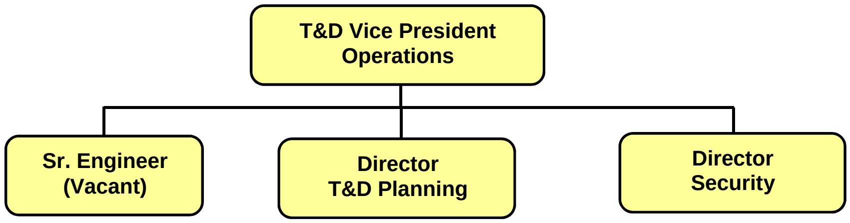
- National Grid operations and maintenance resources perform day-to-day activities covered by fee compensation and perform capital work as a pass-through expenditure.

[1] DR 4
[2] DR 4, MSA Section 4.2 Operation and Maintenance
[3] DR 4, MSA Section 4.4(A) and 4.15(A)(3)
[4] DR 4, MSA Section 4.5
[5] DR 4, MSA Section 4.16(D) and (E)
[6] DR 4, MSA Section 6.1

Total Manager Compensation Fees are not adjusted when the same resources perform capital or storm work, thereby enhancing National Grid's potential profitability.

- LIPA's T&D oversight organization is minimal, as illustrated in **Exhibit 12-1**. However, system reliability has been remarkably good (see **Chapter 9 - System Planning**).

Exhibit 12-1
LIPA T&D Oversight Organization



12.3.2 National Grid makes effective use of mobile workforce tools.

- LIPA/National Grid's practice is to employ mobile data terminals in the vehicles used by the Emergency Service Specialists (ESSs). ESSs are the people who respond to trouble calls (lights out, pole down, etc.) whether during normal business hours or after hours.

- Mobile data terminals are not used by field forces that do planned construction and maintenance work. Instead, they rely on mobile telephones. The workers have I-phones, which can be used to communicate text messages as well as pictures and other media.

- This is appropriate in view of the low frequency of occurrence of immediate response work for these workers. It is also cost-effective based on the relatively low cost of the I-phones.

12.3.3 Numerous T&D inspection and maintenance programs make important contributions to system reliability.

- LIPA has achieved excellent T&D system reliability during the last several years. This level of system reliability cannot be maintained over an extended time without the use of a thorough program for identifying and responding to maintenance issues.

- National Grid reported the following distribution, substation and transmission system inspection and maintenance programs that target reliability improvements.[7]

  - Mitigating tree caused power interruptions is an important contributor to system reliability due to the combination of both high population and tree density throughout much of LIPA's service territory. The core distribution vegetation

[7] DR 99

management program is LIPA's circuit trim program – the Vegetation Management Program. Circuits are selected for trim each year primarily by their prior three year vegetation related interruption history. Other factors in determining circuits to be trimmed are the field conditions and the historical trim guideline for that circuit. Over the past 6 years, identifying and removing hazardous trees and limbs (often located outside the specified line clearance zone) has been included under the storm hardening program.

- Over time, localized customer electric loads can increase to the extent that they may overload their transformers and cause an outage. The transformer load management program evaluates and prioritizes distribution transformers loads using a predictive algorithm. The program seeks to replace transformers in advance of an emergency replacement during a heat storm.
- The transmission wood pole inspection program calls for re-inspection every 11 years. In 2012, all transmission wood poles were inspected for adequate strength. Poles with insufficient strength are replaced in the program.
- The distribution wood pole inspection program (for adequate strength) calls for re-inspection every 11 years. Starting in 2013, all distribution poles were scheduled to be inspected over the next 10 years. Based on the results of this inspection, poles will be replaced or reinforced based on remaining strength.
- Reliability centered maintenance methods were developed to determine intervals for preventive maintenance tasks for specific substation component types such as transformers, regulators, circuit breakers, pump houses, load tap changers (LTCs), network protectors and transformers and the DC battery system. The method begins by establishing a preliminary task interval based on statistical or historical trending analysis utilizing failure data or experience maintenance interval data. Monthly condition assessments are made based on observed characteristics of all equipment in each substation yard. During the inspection, cyclometer readings are taken for breakers and transformer bank LTCs. Also, the transformer bank oil temperature is recorded during this process. The cyclometer readings are used to calculate the number of operations since the equipment was last overhauled or tested. This information is used to support the maintenance processes, frequencies and substation maintenance efforts to improve reliability.
- A transmission reliability centered maintenance program is utilized on major transmission system components. This maintenance program includes tree trimming, thermovision, annual walk downs and acoustic inspections, leaf on/leaf off clearance patrols, and walk-ride inspections that are performed annually. In addition, emergency/special patrols are performed as necessary following a trip or on an as needed basis to identify specific problems or reliability related issues.

12.3.4 Worst performing circuits are regularly analyzed and addressed to improve system reliability.

- By definition, worst performing circuits will always exist. Most utilities identify, analyze and track worst performing circuits in order to find opportunities to improve reliability. An important measure of the success of such a program is the re-occurrence of circuits that appear on the list over a few years. Many utilities struggle with poor performing circuits that are classified as worst performers year after year.

During the period 2007 through 2012, the program did not list any circuit as a worst performer more than once due to equipment related problems. Only four circuits appeared on the list more than once due to vegetation management issues.[8]

- Worst performing circuits are selected based on distribution related outages and for vegetation related outages.[9]

  - Independent programs are run for both these selection criteria.
  - These circuits have a large multiplier effect of LIPA's overall reliability since the worst 5 percent performing circuit's impact 35 percent of the total system wide customer interruption outage minutes.
  - During 2007- 2012, 181 circuits were targeted for additional attention (a total of 2,444 primary circuit miles).
  - The Circuit Improvement Program (CIP) addresses LIPA's poorest performing distribution circuits (typically targets 4-5 percent).[10] Worst performing circuits are remediated under the CIP.
  - The CIP provides for a 100 percent field inspection of all primary distribution lines/facilities with special emphasis on three-phase main circuits (patrolled by foot).
  - Starting in 2012 a supplemental acoustic based inspection (Exacter) was also performed for each CIP circuit.
  - A computer application tool known as the Long Island Geographic Hotspot Targeting System ("LIGHTS") was developed in 2011 to better monitor performance for targeted areas.

12.3.5 Preventive maintenance is properly scheduled, performed and information is recorded.

- National Grid's Distribution Support group is responsible for maintaining, scheduling and recording preventive maintenance information for the Substation Maintenance Division. Distribution Support has four work coordinators who use a software application called Maximo to perform the following.[11]

  - T&D system equipment is entered into Maximo by location, identification number and type, along with maintenance frequencies for each piece of equipment.
  - On an annual basis, all work is downloaded to an excel spread sheet for use by local work coordinators. Crews are assigned work via a specific hand written inspections or work sheets. Upon completion of the assigned tasks, the work coordinator makes the appropriate entries into Maximo in preparation for the next maintenance cycle.

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[8] DR 122 and 741
[9] DR 122
[10] DR 99
[11] DR 776

- Inspection and repair tickets are reviewed by the respective local area manager. All pending demand work items that result from maintenance inspections are also recorded in Maximo.
- Paper maintenance records are stored in each respective region and in the central maintenance office in Hicksville.

• Information for protective relays and telecommunications equipment is entered into a Microsoft Access Database called the "Relay Maintenance File" (RMF).

  - The RMF file contains the specific details of each relay (substation, identification number, zone of protection, maintenance frequency, etc.).
  - Maintenance frequencies are entered into the RMF file for each protective relay set.
  - The RMF file has query selections to view equipment due for maintenance. Work is assigned by due dates by calendar year and equipment availability by the Relay Field Supervisor.

• Relay Technicians are assigned work by the Relay Field Supervisors and they complete hand written test report forms and/or computer generated automated test reports.

  - Test reports are reviewed by the Relay Field Supervisor. Technical assistants assigned to each field supervisor receive the completed test reports and update the maintenance data fields in the RMF database.
  - Pending and completed work is contained in the ESO-Relay 8-4 Database. Maintenance records are stored in the Protection & Telecom office in Hicksville.

• The Substation Operations organization is staffed by 32 Multi Station Operators and a small management team of three people. Each Multi Station Operator has a permanent substation assignment list.

  - Inspection assignments are automatically downloaded into a mobile data system for each operator. The mobile data system has a unique screen or field for each piece of equipment and the operator must record the inspection results on the screen.
  - Multi Station Operators are scheduled to visit each substation monthly to inspect the equipment, the grounds, and fencing. Inspection data, such as equipment operations and system condition, as well as any observed abnormalities, are recorded. Supervisors review the abnormal entries and make assignments for maintenance repairs or further investigation. While some of the abnormal observations are addressed by the Station Operator during the time of the inspection, many are assigned to other organizations to be addressed the next day or in the future based upon the priority. In any event, observations are recorded and tracked.

• Circuit inspections are performed annually for the circuits selected for the respective year's program. The inspections are typically started in September with circuit inspections continuing until the following April. Due to delays associated with Hurricane Sandy the 2012/2013 program inspections were scheduled to be concluded in June 2013.

- Primary cable testing on the T&D system is performed throughout the year and is a continuous effort. Exit and mainline dip cables (cables that are routed under roadways) are selected for testing annually based on factors that include:

  - Number of failures
  - Prior test history
  - Number of customers served
  - Age of the cable
  - The existence of critical facilities on the circuit
  - Length of the cable

- Cable failure testing is performed as needed (i.e., after a failure occurs) throughout the year.

- Infrared "hot spot" scans of 50 percent (alternately half each year) of the overhead distribution lines are conducted annually. The last infrared scan of distribution lines was completed mid-year.

- Infrared "hot spot" scans of 100 percent of the overhead transmission lines are conducted annually. The last infrared scan on of the overhead transmission system was completed on May 23, 2013.

- Field inspections are part of the annual refresher training for personnel who have storm damage survey assignments (for major storms). In a year without a major storm, these field inspections are performed between the end of February and the end of April. This training/inspection program is cancelled during a year in which personnel responded to and performed inspections as a result of an actual storm in the past year. The last time emergency response field inspections were performed was during the period October 29 through November 14, 2012, in response to Hurricane Sandy.

- National Grid reports on several metrics that are directly related to the preventive maintenance program.

  - Demand Substation Maintenance Backlog measures the number of high priority substation demand maintenance jobs not completed (i.e., backlogged), and is measured as the number of jobs in the substation maintenance backlog at the end of each contract year as shown in **Exhibit 12-2**.
  - Primary Cable Faults represents the average number of days required to return faulted primary cables to normal service. Primary cable includes substation exit cables, three-phase main line and main line dips (cables that pass under streets and roads), and three-phase commercial and industrial primary underground distribution (CIPUD) cables as shown in **Exhibit 12-3**.

Exhibit 12-2
Substation Maintenance Backlog

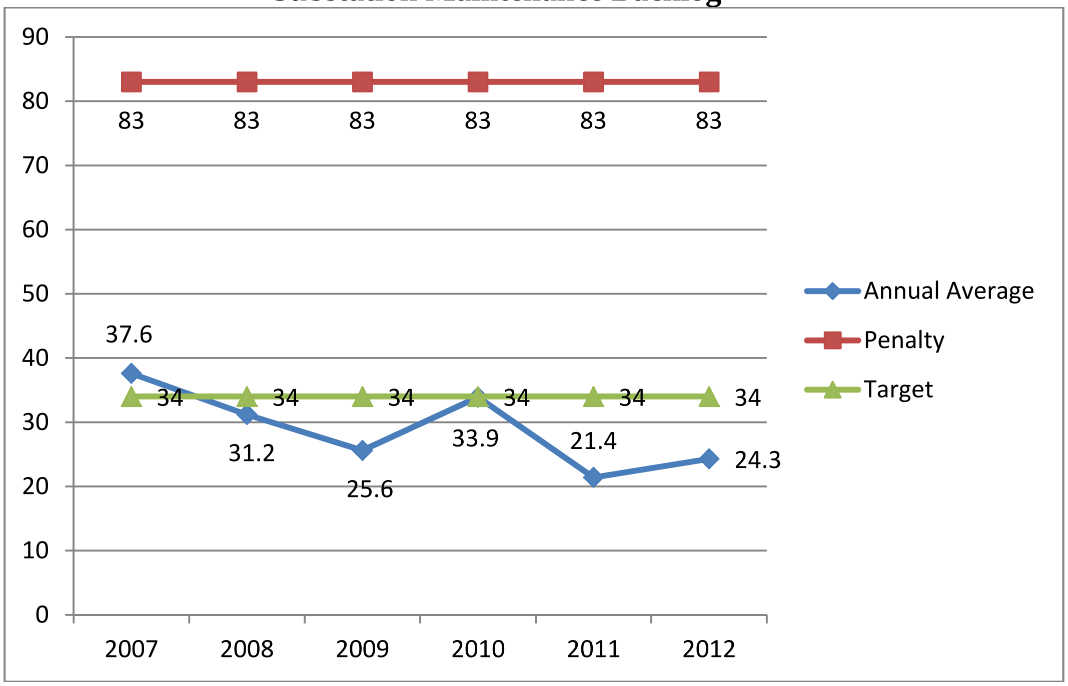
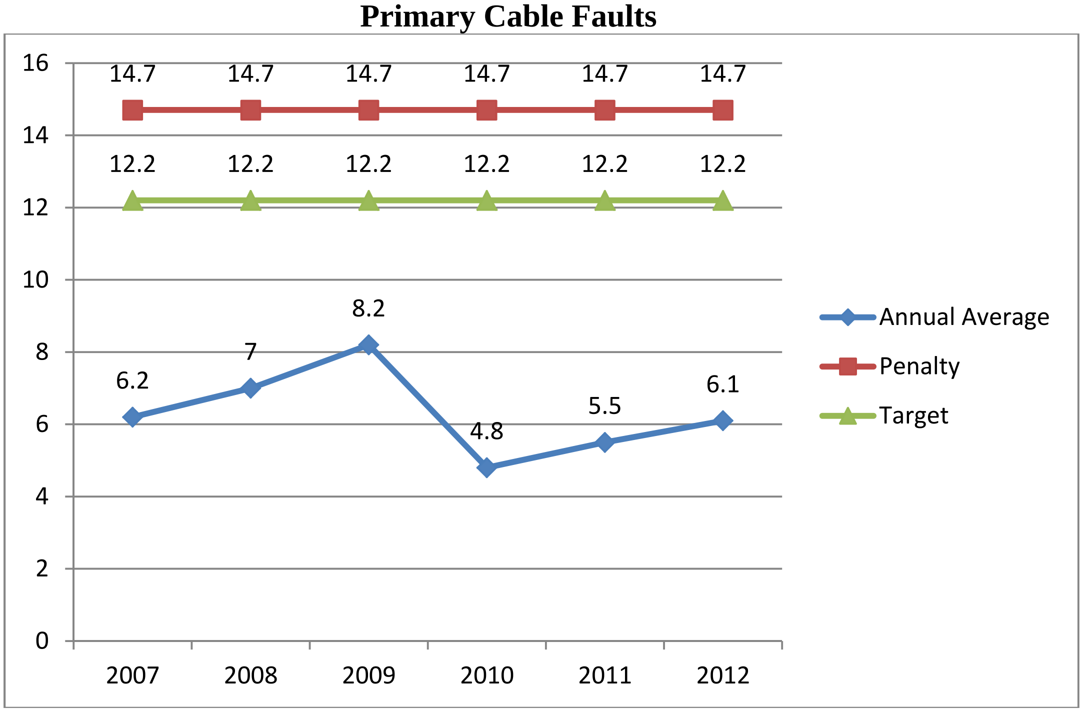


Exhibit 12-3
Primary Cable Faults

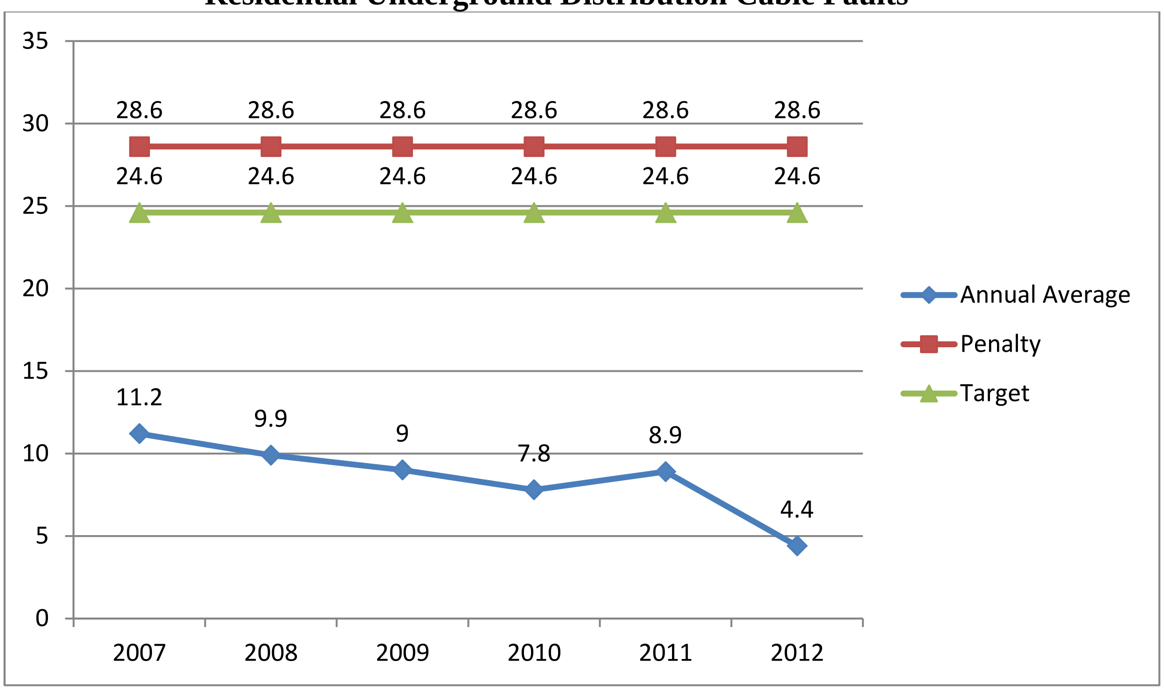


- Residential Underground Distribution (RUD) Cable Faults tracks faults in all primary loops, both single and multiple phase in residential service areas as shown in **Exhibit 12-4**.
- As depicted in the charts, National Grid has performed well against performance targets.

- The charts indicate that, despite National Grid's performance, the targets and penalty levels have not changed in many years because of the terms of the contract. The chart also suggests that the targets could be adjusted to provide greater incentive to PSEG for economically improving system reliability.

- National Grid reports maintenance activity monthly as one of three components in the Workplan Completion Index. Prior to the beginning of each contract year, National Grid and LIPA agree to the O&M Workplan, the Capital Workplan and the Corporate Initiatives for such contract year. The O&M Workplan contains the entire T&D maintenance annual plan for the respective year. During the contract year, subject to LIPA's approval, National Grid may exclude certain planned maintenance activities in any particular year. Any excluded maintenance activities are added to the subsequent year's O&M Workplan.[12]

Exhibit 12-4
Residential Underground Distribution Cable Faults



Source DR 282

- Collectively, these programs represent a summary of how preventive maintenance is identified, scheduled, performed and recorded to provide pertinent information.

[12] DR 6 and 13

12.3.6 Vegetation management cycles and standards are consistent with industry practices and appropriate for LIPA's service territory.

- LIPA has about 1000 miles of transmission lines. National Grid trims about 200 miles per year, which puts the transmission system on a five year cycle. A five year trimming program is not unusual for a large transmission system.[13]

- LIPA has just over 9,000 miles of distribution lines. In 1994, a five year cycle for its distribution system was established. Analysis of the effectiveness of the program revealed that some circuits needed to be on a three year cycle and some could wait as long as seven years. As a result, LIPA adopted a mixed cycle program.

- In addition to planned trimming cycles specific areas along the distribution system are addressed/trimmed based on several different inputs, i.e. customer, storm impact, serviceman observation, line clearance, and supervisor observation.[14]

- The planned trim-miles for the years 2008 – 2012 were 1600 miles for the distribution system and 200 miles for the transmission system. The completed miles were more than planned in some years due to additional work that was performed to address reliability concerns in specific pockets of the system as shown in **Exhibit 12-5**.

Exhibit 12-5
Vegetation Management Performance

Year	Transmission Miles Planned	Transmission Miles Trimmed	Distribution Miles Planned	Distribution Miles Trimmed
2008	200	218	1600	2001
2009	200	200	1600	1671
2010	200	200	1600	1600
2011	200	200	1600	1718
2012	200	200	1600	1600

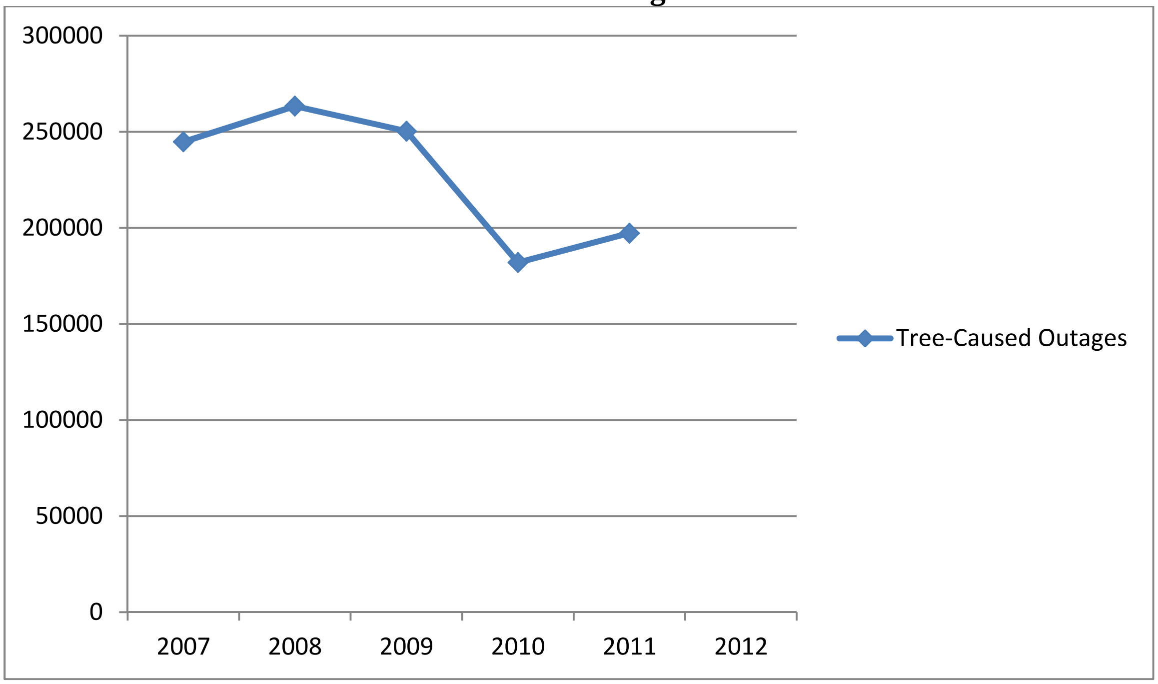
Source: DR 6 and 724

- Moreover, reliability performance has been good, which suggests the vegetation management program has achieved the desired results.

- In 2012, the vegetation management program was disrupted by Hurricane Sandy. Hurricane Sandy resulted in the loss of approximately five weeks of time for contractors to perform their work plan. Nonetheless, all distribution circuits within the 1600 mile distribution program and all transmission circuits within the 200 mile transmission program for 2012 were reported as completed prior to year end. All tree contractors provided the necessary resources in order to complete their schedules on time.[15]

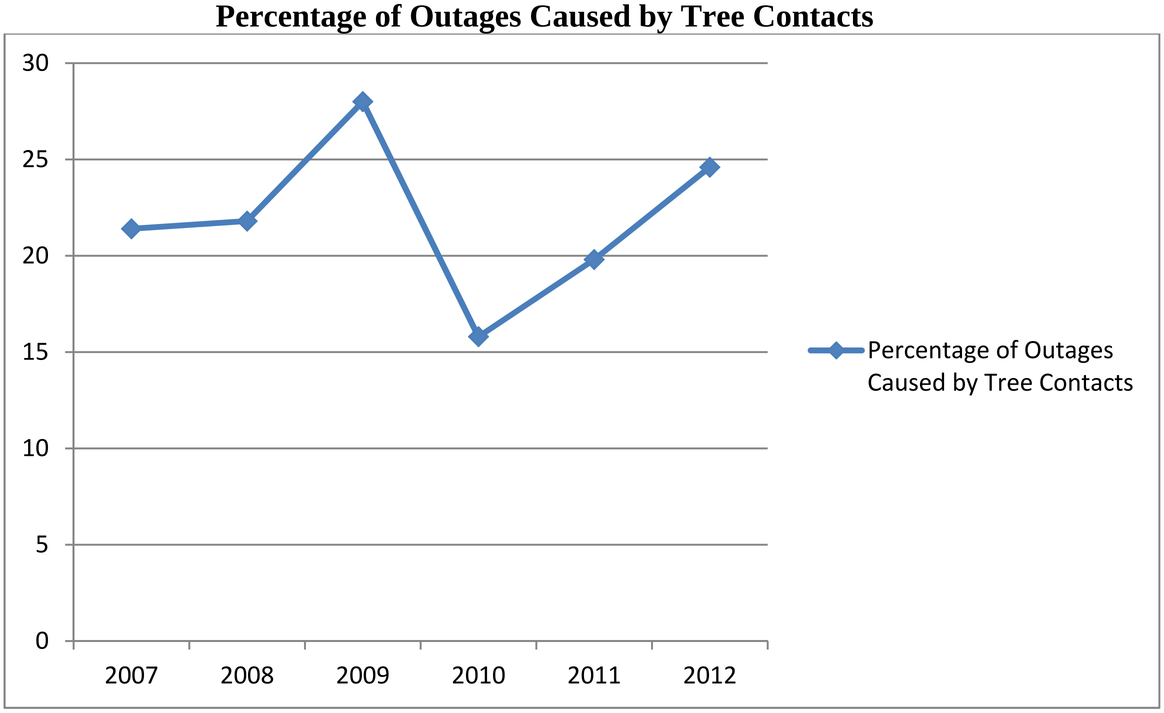
[13] DR 125
[14] DR 724
[15] DR 125 and 732

Exhibit 12-6
Tree-Caused Outages



Source: DR121 and 282

Exhibit 12-7
Percentage of Outages Caused by Tree Contacts



Source: DR121 and 282

- Reliability data indicate that the program is generally effective. As depicted in **Exhibit 12-6**, the incidence of tree-caused outages has declined, while the percentage of outages caused by tree contacts has varied from about 15-25 as shown in **Exhibit 12-7**.

- Notwithstanding the general effectiveness of the vegetation management program, tree contacts have been the most common cause of outages for LIPA's customers for the last several years, whether during storms or on "blue sky" days. While this is not uncommon in the electric utility industry, it still presents an opportunity for improving service.

12.3.7 National Grid does not perform economic cost and benefit analyses in its repair/replace decision making on behalf of LIPA.

- LIPA does not have formal written procedures that govern the process used by National Grid to make replace or repair decisions.[16] National Grid performs detailed analyses of problems encountered on the T&D system as part of its project justification process. However, a direct comparison of repair cost versus replacement cost is not done.

- For program based repair vs. replacement, decisions are based on observed field conditions and/or the availability of replacement parts, with limited consideration of costs[17]. Examples include:

  - Distribution Pole Replacement - poles are inspected and tested (sounded and bored) by a third party vendor to determine the shell strength remaining. Based on this assessment of remaining strength, deteriorated poles are either scheduled for replacement or re-enforced with steel trusses to extend their life.
  - Underground Cables are tested using Tan Delta and Partial Discharge to determine remaining insulating system life before repair or replacement decisions are made.
  - Pole top and pad mounted transformers returned from the field are evaluated by qualified shop personnel who will determine if a unit can be returned to service or scraped.

- The MSA provides an economic incentive to avoid significant repairs and instead replace, since National Grid is reimbursed for capital expenditures, while repairs and other corrective maintenance fall within the fixed fee compensation amount for operating and maintaining the T&D system.

- Direct observation of T&D operations and maintenance revealed the philosophy that "We don't want to have to come back." It is easier to replace equipment and parts that have been damaged or are otherwise not functioning than make a repair and take a chance that a subsequent failure may occur. And, significant replacements are

[16] DR 68
[17] DR 68

capital expenditures with full reimbursement for labor, equipment and materials while preserving O&M fees.

12.3.8 Assumptions regarding typical life expectancy of key T&D system equipment are appropriate and consistent with good utility practices.

- Equipment life expectancy assumptions are predicated on industry standards and operating experience. Actual life expectancies may vary based on factors such as equipment manufacturer/vendor, installation workmanship, operating conditions, loading and other equipment history.[18]

  - Estimated life expectancies for key T&D equipment usually range 30-40 years. This is true for substation equipment, pole-mounted transformers, switches and voltage regulators. Wood poles, porcelain insulators and conductors (lines) are expected to last about 50-60 years.
  - Equipment such as capacitor banks, automatic sectionalizers, reclosers and lightning arrestors (which experience more wear and tear) have a shorter expected life expectancy, around 20 years.
  - Underground cables and pad-mounted switchgear are expected to last about 35 years, while splices and terminations are estimated at 25 years.
  - Utilities including LIPA, usually expect transmission equipment to last longer than overhead and underground distribution. Transmission towers and footings are estimated at 80-100 years, and overhead and underground cable at 80 and 40 years, respectively.

- Equipment life expectancies for the LIPA system are similar to those used by other utilities.

12.3.9 The feasibility of converting existing overhead lines to underground construction has been studied extensively.

- Most utilities have, at one time or another, studied the practicality and cost of placing electric distribution lines underground. In recent years, most of these studies have been prompted by extreme weather events, such as ice storms and hurricanes that left customers without power for an extended amount of time. Naturally, underground cables are less subject to damage from severe weather conditions, mainly lightning, wind, ice loading and damage from fallen trees. Also, underground lines and equipment are usually much less subject to theft and vandalism. Restoration time for underground systems is typically longer than overhead systems. Normally, studies that are performed following major outages cite these advantages for moving overhead lines to underground.

- The major disadvantage of converting overhead to underground circuits is cost. Undergrounding is more expensive because the cost of burying cables is several times greater than the cost of constructing overhead power lines. Although estimates vary,

[18] DR 730

the cost of an underground power cable is typically estimated at two to four times the cost of an overhead power line. In highly urban areas the cost of an underground system can be many more times as expensive as overhead. Maintenance is also more expensive for underground cables, because overhead lines are more easily accessible.

- In December of 1998, Resource Management International Inc. presented the results of an investigation on the "Assessment of Transmission and Distribution Construction Practices and their Impact on Public Safety" to LIPA.[19] The report found that the cost of undergrounding the Long Island T&D system would be $14.7 billion and could potentially double customer rates. Current cost estimates of undergrounding the Long Island T&D system are even higher due to increased material and labor costs and changes in design standards. Following review of the 1998 study, the LIPA Board of Trustees initiated a subsequent investigation to provide additional information regarding the costs and benefits associated with underground versus overhead construction and concluded that the costs outweighed the benefits.

- In light of the continued public interest in placing electric lines underground, LIPA revisited the costs and benefits of underground construction in 2005. LIPA engaged Navigant Consulting to update the earlier study and undertake a survey of the current state of the industry on the issue of undergrounding electric distribution systems. The following observations and conclusions were drawn.

    - Almost all companies that investigated undergrounding existing overhead systems have concluded that the cost to underground all existing overhead distribution facilities is prohibitive. Cost estimates for underground construction are estimated at ten times the cost of overhead construction varying from $500,000 to several million dollars a mile.
    - A study performed for LIPA by KeySpan Energy estimated the cost to underground the Long Island distribution system at $24.8 billion. This estimated cost excluded the cost to convert services and third party attachments, and was based on an estimated average per mile cost of $5.4 million for a typical mile of primary main and $1.7 million per mile for a typical primary branch line. Another study performed by KeySpan for LIPA estimated the cost of undergrounding transmission lines that need to be upgraded or built new during the course of regular business over the next 25 years to be $2.1 billion. When considering the cost of undergrounding the distribution system plus the costs of undergrounding the existing transmission lines and the LIPA portion of customer service drops, the potential impact on rates was estimated to up to a 154 percent increase.

- Moreover, while underground systems are more reliable than overhead systems under normal weather conditions, suffering only about half the number of outages of an overhead system, they are not immune to damage.

[19] DR 725

- According to the Navigant study, the repair time for underground systems can three to four times longer than for overhead systems when damage does occur.
- LIPA's experience has been that underground restoration times can be almost 2.5 times longer than for an overhead system.
- Underground lines have proven to have a shorter useful life than overhead lines as they are more susceptible to corrosion than overhead lines and can be damaged by flooding, tree roots, rodents, and people digging up the lines.
- Underground lines connecting to overhead lines are still vulnerable to lightning. Also, where only partial circuits are placed underground, the overhead portions are still susceptible to the types of events that affect other overhead lines.

- Thus, LIPA concluded that burying existing overhead power lines could dramatically increase costs and would not completely protect consumers from storm related power outages. LIPA is concerned about the adverse rate impact a wholesale undergrounding program on Long Island would present, but recognizes that there may be potential to improve system performance and aesthetics through selective undergrounding. To improve system performance and aesthetics while mitigating rate impacts, LIPA is examining a targeted undergrounding program to place underground selected portions of circuits experiencing the poorest performance.

12.4 Recommendations

12.4.1 Increase the effectiveness of the vegetation management program by further refining analysis of tree-related outages.

12.4.2 Develop and implement a rigorous procedure that requires a thorough analysis and direct comparison of the costs of repairing versus replacing T&D system equipment. While other factors, such as system reliability, should be analyzed as well, LIPA should be aware of the cost-effectiveness of each project or program, and the impact it will have on customer costs.

12.4.3 Establish an asset management model that supports the LIPA T&D preventive maintenance program.

- Key components of the asset management model used by PSEG should be brought to the PSEG-LI T&D operations and maintenance program, and include:[20]

  - Investment Evaluation System – This system collects demographic and cost information for each maintenance project as well as scoring data that is used to rank and prioritize each project. The tool allows decision makers to perform customized scenario analyses to maximize value or minimize risk. Results are used to form the investment plan for the upcoming budget cycle.
  - Centralized Asset Registry – This database serves as a central location for T&D system equipment type, operating specifications, and locations. Functionality also includes the ability to search for equipment by characteristics.

[20] DR 726

- Reliability Centered Maintenance – This program is used to achieve improvements such as the establishment of safe minimum levels of maintenance, changes to operating procedures and strategies, and the establishment of capital maintenance plans. Reliability centered maintenance helps to improve cost effectiveness, equipment availability (uptime), and a greater understanding of the level of risk to be managed.
- Computerized Maintenance Management System – This system serves as a repository for consolidating data about T&D system components and facilitates data analysis and reporting. The system supports the ranking and prioritization of projects, supplies data for reliability centered maintenance (RCM).
- Work management – This system stores and tracks items included in the inspection and maintenance program. It provides notice when inspections need to be scheduled or when maintenance activities are overdue and stores the results of inspections, triggering alarms if necessary.

13. WORK MANAGEMENT

This chapter addresses the operations and maintenance work management activities performed for LIPA by its contractor, National Grid under the MSA. A number of work management elements are also addressed in **Chapter 10 – Capital Program and Project Planning and Management**.

13.1 Background

An effective work management program provides a utility with a net positive benefit that can be directly related to improved performance and significant cost savings for the following reasons:

- Work planning improves efficiency and effectiveness in the use of human resources.
- The utility is better able to align its workload with available resources and determine the optimum work force for each area or function, often translating into reductions in labor costs.
- Work management supports the budgeting process by identifying and quantifying the workload requirements for planned activities. Work management also assists in the determination of the time frame for activities consistent with the utility's ability to finance the work.
- Employee utilization is improved because managers have the tools to monitor and direct resource distribution depending on the workload.
- Efficiency is improved by getting more work or higher quality work done with the same number of people.
- Effectiveness is improved by focusing available work-hours on higher priority tasks and delaying or eliminating less important or unnecessary work.
- Work management provides management the tools needed to benchmark its efforts against other utilities.
- Benchmark data developed from consistent reporting also gives management the information needed to negotiate with its union to define better work rules.

The approach to assessing work management practices relies on standards set forth by the Project Management Institute (PMI) and the Institute of Asset Management (IAM).

- PMI standards include A Guide to the Project Management Body of Knowledge (PMBOK) and the Organizational Project Management Maturity Model (OPM3). OPM3 is an assessment framework for gauging the level of project management practice for Planning, Execution, and Monitoring and Control.
- IAM maintains the Asset Management standard Publically Available Specification (PAS 55). PAS 55 describes organizational enablers as "structural, cultural, technological, and human resource practices. .

The standards define the processes that comprise the work management program. These processes are summarized in **Exhibit 13-1** below.

Exhibit 13-1
Work Management Processes

Process	Descriptions
1. Planning	Longer term processes that manage work initiation and assure availability of resources to perform that work. Planning horizons range from a month for near term work to multi-year for large capital projects. Forecasts are needed for unplanned work levels.
2. Work Preparation	Processes that define in detail what is to be done, prioritize the work, and dispatch needed resources like employee and/or contract work hours, access to the work site, material, equipment, vehicles, and other logistics. Time frames for this group vary from minutes (in the case of emergencies) to months or years for large projects.
3. Work Execution	Processes that execute work that meets customer expectations. The work is performed by employees and/or contractors.
4. Monitoring & Controlling	Includes scope change control, performance measurement, cost control, reporting, utilization reporting, and identification of actions to improve performance.
5. Enabling Processes	Processes that support the other work management process groups.
Processes 1,2 and 4 are addressed in PMI standards; Process 5 is addressed by the IAM.	

NorthStar examined the work management of National Grid groups which perform construction and maintenance under the MSA, as summarized in **Exhibit 13-2**.[1]

Exhibit 13-2
National Grid Long Island Construction and Maintenance Departments[2]

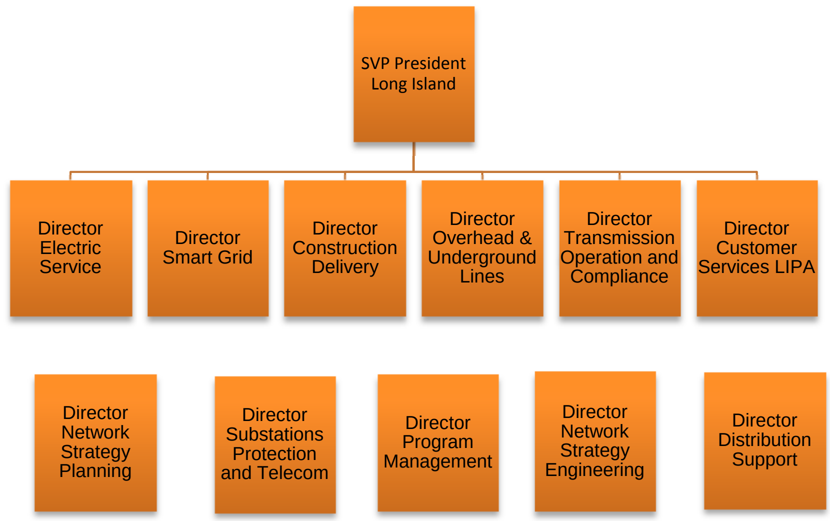
Department	Description of Work Performed	Number of Employees
Work Execution		
Overhead & Underground Lines (OH/UG Lines)	Construction and maintenance of the transmission and distribution systems.	319
Electric Service Operations (ESO)	Control Center staff & Emergency Service Specialists (108 "troublemen") responding to unplanned service requests on a 24/7 basis. Other staff includes supervisors, dispatchers, and system operators.	191
Substation, Protection, & Telecommunications (SPT)	Construction and maintenance of substations, relays, and telecommunications plus other assigned assets.	215
Work Execution Total		725
Support Departments (Planning, Work Prep, Monitoring and Controlling)		
Distribution Support	New or existing customer request handling; scheduling & work coordination; and other support for all divisions.	89
Construction Delivery	Contract management, vegetation management, public works management, and construction management on capital projects.	47
Program Management	Program planning, work plan development, project management, cost management, and performance reporting for all divisions.	13
Support Total		149
Execution and Support Total		874

Source: DR 2

[1] DR 93
[2] Some of these organizations are also responsible for capital project delivery.

As shown in **Exhibit 13-3**, each department reports directly to the Senior Vice President of National Grid - Long Island (National Grid).[3] LIPA's Vice President of Operations is responsible for oversight of the National Grid work in this area.

Exhibit 13-3
National Grid Construction and Maintenance Departments



National Grid's T&D construction and maintenance personnel are assigned to four divisions (containing 12 workout locations), in Nassau and Suffolk counties: Queens/Nassau, Central (also in Nassau County), Western Suffolk, and Eastern Suffolk. Distribution Support, Construction Delivery, and Program Management organization resources are often assigned to one or more of the divisions as shown in **Exhibit 13-4**.

Exhibit 13-4
Support Function Deployment

Function	Reporting Department	Scope	Location
Field Coordinator	Construction Delivery	County	County
Public Works	Construction Delivery	Division	Central
Vegetation Management	Construction Delivery	Division	Central
Contract Management	Construction Delivery	Division	Local
Project Management	Construction Delivery	Division	Local
Work plan & Cost Management	Program Management	Division	Local
Scheduling & Work Coordination	Distribution Support	Division	Local
Customer Order Fulfillment	Distribution Support	All Areas	Central

DR 2, IR 121, 122, and 127

[3] DR 2

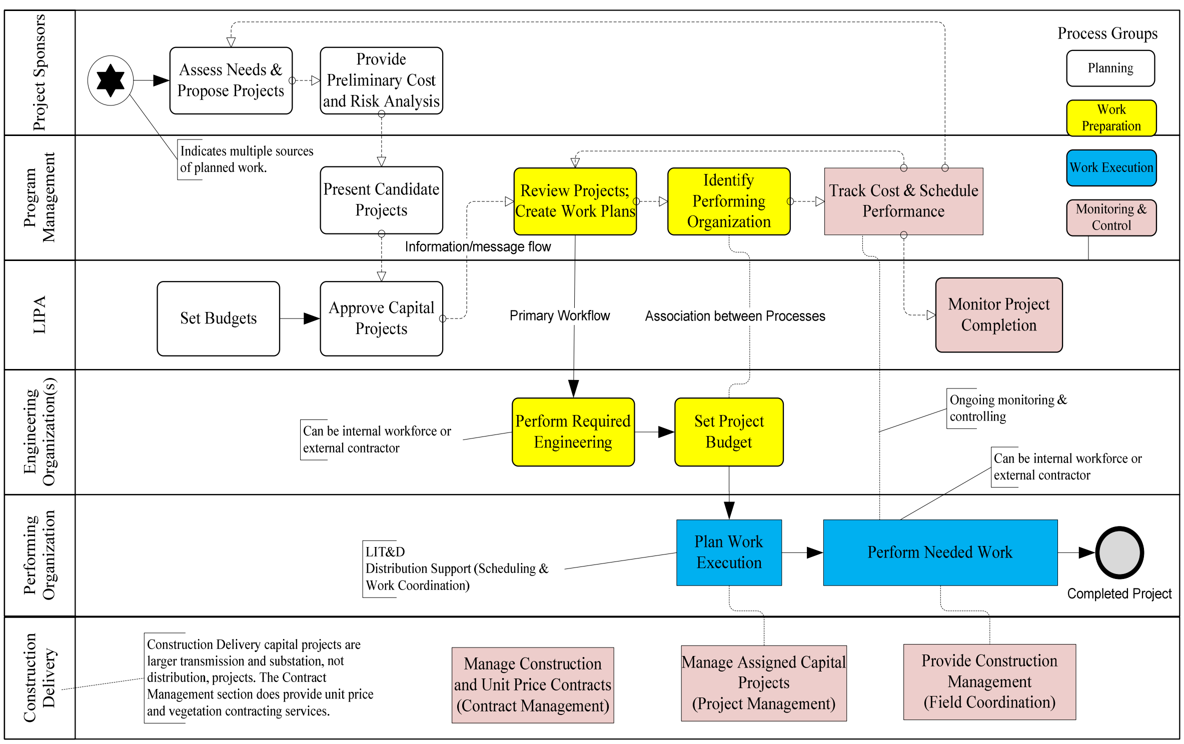
T&D activities can be generally separated into two categories: planned and unplanned work. **Exhibit 13-5** lists typical electric utility planned and unplanned work activities.

Exhibit 13-5
Planned and Unplanned Work

Planned	Unplanned
• Capital projects – transmission and distribution, substation, protection and telecomm. • Vegetation control (tree trimming) • Planned maintenance requirements including Work Plan elements required by the MSA	• Emergency service outages/reports of anomalies, e.g., "flickering lights" • Unplanned maintenance, e.g., outage follow up by crews after an initial response • Customer requests for new services or changes to existing services • Public works requests to support projects undertaken by public sector agencies

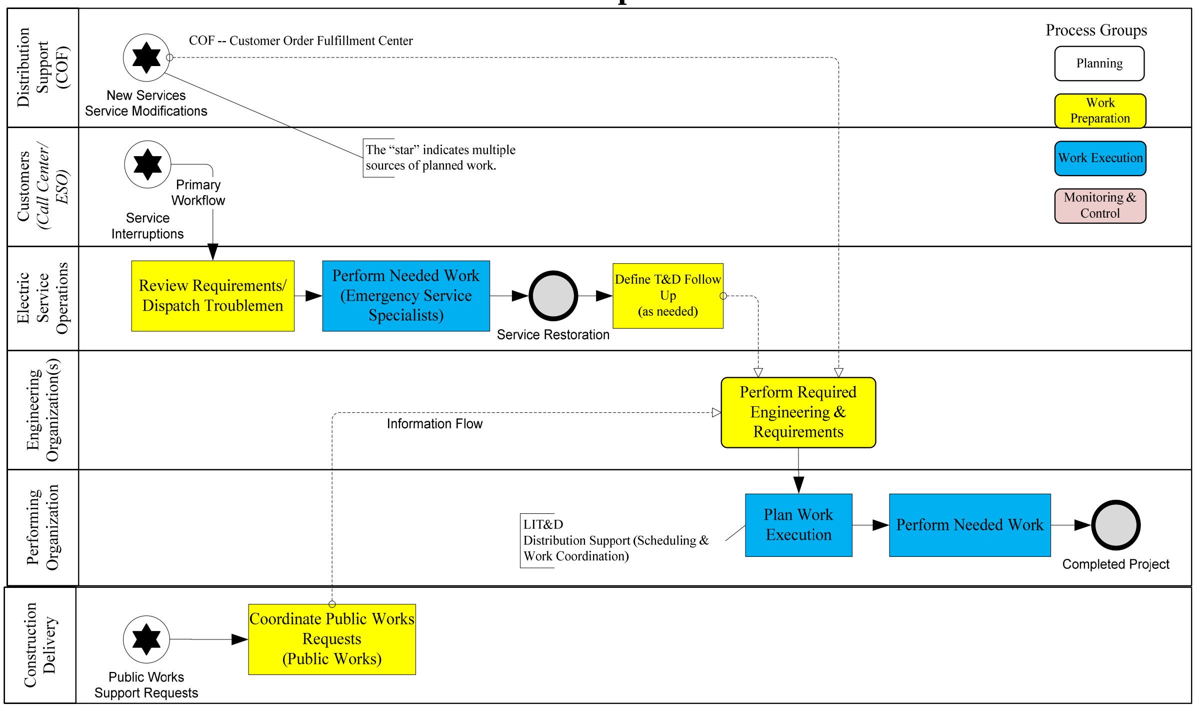
Exhibits 13-6 and 13-7 outline the roles of National Grid organizations and LIPA in performing planned and unplanned work. The role of each organization in the work management process is indicated by the color codes.

Exhibit 13-6
Flowchart for Planned Project Work



Planned work mainly consists of capital projects. Other planned work includes MSA-required and other O&M tasks. Capital projects are discussed in **Chapter 10 – Capital Program and Project Planning and Management**.

Exhibit 13-7
Flowchart for Unplanned Work



Unplanned work includes new service or modified service requests, service outages or other malfunctions, and public works requests from municipalities and other agencies. The outages or malfunctions require fast responses. Public works and new or expanded services are less urgent but require coordination between LIPA/National Grid and the customer or customer representative. With the exception of outage or malfunction requests, most unplanned work will require some level of engineering, followed by work orders to the field to execute the request.

13.2 Evaluative Criteria

- Are major workforce groups covered by work management systems to assign, execute, and control the work?
- Do work management systems appropriately interface with other key systems such the customer information system, dispatch, and outage management?
- Are existing systems current and sufficiently robust and flexible?
- Do existing systems provide timely, accurate information for LIPA customers and other stakeholders?)
- Are work management systems used effectively to schedule and manage field crews, including transportation, equipment, and materials?
- Do the workforce and work management systems feed back into performance improvement opportunities?
- Are programs and projects effectively converted into short-term and day-to-day work?)
- Are work program and project schedules managed effectively on a day-to-day basis?

- Do existing systems and procedures provide adequate data to analyze work volumes and staffing requirements for all major work force groups?
- Has National Grid established appropriate decision-making processes and controls to assure that staffing levels are adequate for both day-to-day operations and emergencies and are assumptions documented when planning workforce requirements for new projects and continuous operations where history is inadequate to determine staffing levels?
- Are KPIs established by and reported to/by LIPA appropriate?
- Does LIPA/National Grid use mobile technology for its field work crews and do existing systems provide timely and accurate information to customer contact personnel?
- Does LIPA/National Grid measure and manage employee availability, utilization, efficiency, productivity and effectiveness in an appropriate manner?
- Do LIPA/National Grid use process and project performance data as a basis for continuous improvement?
- Has LIPA developed appropriate plans for any work management system conversions necessitated by the switch from National Grid to PSEG-LI?

13.3 Findings and Conclusions

13.3.1 National Grid does not use a work management system to effectively plan, monitor and control the work of major work force groups.

- National Grid's primary work management systems, Microsoft Project, Oracle's Primavera P6 and IBM's Maximo, are sufficiently robust but National Grid does not utilize their full capabilities.

  - Primavera P6 is project portfolio management software used throughout the construction and utilities industry. Its capabilities include portfolio management, program management, project management, planning and scheduling, resource management, budgeting and costs, and reporting and analytics.
  - Maximo is a work order management system.

- National Grid does not use a system or formal process to perform and integrate the work management processes described in **Exhibit 13-1** (Work Management Process), to monitor productivity and utilization of the workforce and compare actual work to targets and goals. The lack of accurate productivity measures:

  - Limits the value of any analysis done to identify future productivity gains.
  - Reduces the value of estimates used for capital and O&M planning purposes and makes in-house versus contractor analyses and decisions subjective.
  - Impacts the ability to determine the optimum number of personnel for each area or function which may be more, less or the same as the current staffing level.

- National Grid does not use a work management system to manage transportation, equipment, and materials requirements. Work Orders contain materials needed for capital projects.

- National Grid does not use workforce or work management systems to identify performance improvement opportunities.

- National Grid does not use a work management system to provide information about rework, failures, and repair history that get translated into corrective actions, infrastructure aging analysis, and repair versus replace decisions in an effective and timely manner.

- The work management system does not interface with other key systems such the customer information system, dispatch, SAP, and the outage management system. Without integrated systems, data for routine reports is dispersed in multiple applications, and the compilation of data for analytic and reporting purposes is a multi-step process. For example, in order to create a variance report:

  - Variance data is downloaded from Oracle into the corporate database Microstrategies Datamart (Datamart).
  - Data from Datamart is input into Microsoft Access to link project cost to work type.
  - Data from Access is input into Excel to create a variance report.

13.3.2 The MSA does not provide incentives to National Grid to improve work management methods.

- LIPA pays the same amount to National Grid regardless of its work force utilization or productivity.

  - LIPA pays National Grid a flat fee for the MSA operations and maintenance services with potential penalties if performance metrics fall below set levels.[4]
  - LIPA pays "pass-through expenditures" for a number of major items such as capital costs, claims and litigation, storm events, taxes, refunds, third-party conservation, and repair for any damage to submerged marine cable.

- The only two metrics contained in the MSA that address the actual performance of T&D work are the Work Plan Completion Index and the Substation Demand Maintenance Backlog, which simply require that a certain amount of work be completed in a year. Furthermore, these two metrics are even less effective due to:

  - The Work Plan Completion Index is set at the beginning of each year based on poorly developed estimates. The work contained in the plan is then adjusted during the year and analysis against the original work plan is not measured.
  - The Substation Demand Maintenance Backlog is based on a number of "jobs" that are not formally defined or quantified in terms of resource requirements. Jobs can be large or small and do not represent the entire workload portfolio.

[4] DR 4, MSA Section 6.1

- National Grid develops the Work Plan and the Maintenance Backlog, measures its own data, and reports to LIPA. There is no independent validation to determine if/when an MSA penalty should be invoked.

13.3.3 National Grid develops work plans which convert programs and projects into short term and day-to-day work for the OH/UG Lines and SPT groups; however, the work plans are not an effective work management tool and the work plan development process is not documented.

- The Program Management Department uses Primavera to generate work plans for OH/UG Lines and SPT activities.

- The work plan is the primary tool for showing work priority and converting plans into short-term and day-to-day work.[5] The work plan is also used as a project report.[6]

- The work plan shows the planned projects, necessary operations and maintenance work, public works projects, and allowances for other unplanned work and non-work elements like training. As work is completed, progress is updated to show percent complete based on man-hours expended

- The work plan does not:

  - Clearly prioritize projects
  - Track productivity
  - Provide summary-level information regarding work force capacity utilization

- The work plan contains data that could be used to determine workforce capacity and utilization. Improved explanation of data in the work plan and wider distribution of the report itself would lead to improved workforce management. A sample project work schedule for two SPT groups in Central Nassau and Western Suffolk counties contained the following data that could be used to assess workforce utilization:

  - Cumulative overtime for the group for the year at 39 percent,
  - Time charged to projects was 57 percent of the total of 30,000 hours
  - Vacations/sick/meetings/training totaled 13 percent, and
  - "DM"(demand maintenance) and "PM" (preventive maintenance) accounted for 30 percent.[7]

- There are no documented procedures for preparing the work plan.[8] The absence of procedures raises the risk of inconsistent planning.

[5] DR 629
[6] DR 293
[7] DR 629 Document E
[8] DR 629

13.3.4 National Grid does not measure and manage employee availability, utilization, efficiency, productivity and effectiveness in an appropriate manner, and does not track improvements in processes and workforce performance.

- National Grid does not track the productivity and utilization of the work force.

- National Grid was unable to provide actual 2012 work hours for each of the 25 MSA tasks.[9] Without actual hour data it is impossible to determine work force productivity.

- There are no performance metrics procedures to report capacity, utilization or unit rate productivity of current staff and contractor resources.[10]

- Supervisory and department reports do not contain information regarding current workload levels, capacity, productivity, and utilization, nor do they identify and track improvements in processes and workforce performance. [11] The reports do not include common work management measures such as:

  - **Standard Time** -- The labor (in manhours) required to complete the assigned work. This is estimated or generated by the work order system.
  - **Earned Value** -- In larger projects, the estimated value of the work performed on a project task or phase expressed in man-hours.
  - **Productivity** -- The ratio expressed as a percentage between the Standard Time or Earned Value in man-hours and the Actual Time in man-hours.
  - **Available Hours** -- The capability to do work expressed. Includes straight time, over time, and available contractor resources.
  - **Utilization** -- The ratio expressed as a percentage of the Standard Times and Earned Value for completed work divided by the capacity expressed as Available Hours.

- **Exhibit 13-8** lists the reports the Director of Overhead & Underground Lines (319 employees plus contractors) uses to monitor and control his responsible areas.

- As shown in **Exhibit 13-8**, there are several reports that contain some metrics, but these metrics could be expanded to provide pertinent data related to job performance.

[9] DR 381
[10] DR 629 Attachment A
[11] DR 281, DR 381, DR 627

Exhibit 13-8
Inclusion of KPIs in Key OH/UG Line Management Reports

Report	Does Report Include Performance Metrics?	Description of Report and Performance Metrics
2013 LI T&D Overhead/Underground Lines Work Plan	Partially	40 page report listing projects to be performed in 2013. Includes hour man-hour estimates and percent complete (based on man-hour expenditures)for each project, but does not summarize information in a useful manner. Does not provide workforce capacity, utilization and productivity information.
2013 Summer Preparedness	Partially	3 page summary status report of work to be done to prepare for the summer peak demand period. Report shows total projects complete, total projects remaining and percent complete without man-hours.
Primary Cable Fault Tracker Report	Partially	E-mail report of the status of each division's efforts to meet year-to-date goals. Provides number of jobs completed and average duration, but does not relate this to goals..
RUD Cable Weekly Report	Partially	E-mail report. Reports the number of jobs by division and the average duration in days..
Scheduling Compliance Report	Yes	Shows through histograms how timely each division was in meeting promised customer delivery dates. Provides the percentage of work completed on time or early, but does not compare performance to any goals.
Safety Performance Report	Yes	MS Excel spreadsheet recording the number of safety incidents for the current year compared to the prior year. Categories include LTIs (Lost Time Injury), OSHA Recordable, and RTCs (Road Traffic Collisions).

Source: DR 627, NorthStar Analysis.

13.3.5 Without productivity data, staffing requirements for day-to-day operations, emergencies, and outages cannot be properly determined, and there are no documented processes or assumptions regarding the determination of staffing levels.

- The Program Management department uses recent history, expected capital budgets, and estimates of program work to forecast employee straight time, over time, and contractor support needs for T&D operations.
  - Program Management prepares histograms to establish the mix of work resources – employee straight time, employee overtime, and contractors. These are estimated for each month in advance of the planning year and include capital projects and estimates of unplanned work. The monthly schedules take into account seasonal variability in workload.[12]
  - National Grid could not provide process documentation describing the preparation and use of histogram forecasts of workforce and contractor requirements.[13]

[12] DR 876
[13] DR 714

- The process for setting Emergency Service Specialist staffing is not formally documented. National Grid could not provide processes or current assumptions underlying the establishment of current staff levels.[14]

13.3.6 National Grid does not consider costs in its decisions to use contractors versus in-house employees.

- Contractors supplement the National Grid employee workforce:
  - All tree trimming is performed by contractors.[15]
  - Contractors are used before the summer period to help prepare the system for peak loads.
  - During the summer, some contractors are retained as a supplementary force in the case of storm-related outages.

- The document "Program Management Internal vs. External Resourcing" describes the rationale to be used in decisions regarding the use of in-house workforce versus contractor workforce in the development of the work plan. Economic benefit is not included as a consideration.[16]

- Program Management policy is to give priority to the employee workforce: "A main objective of this document is to be aware of the need to allocate enough work to internal resources to make sure that our internal crews are productive and efficient in the work they are performing." [17]

- The Program Management document includes a preference matrix to guide the assignment of work to in-house or supplemental resources, but notes that the "development of the work plan will consider many variables such as time of year, overall workload by discipline, workload by region, skill sets/need for training….competition in the marketplace, etc." [18]

- The establishment of the contracts for external resources is governed by general National Grid procedures. There is no process governing the authorization of contractors to supplement the in-house workforce.[19]

13.3.7 LIPA has provided adequately for field communications.

- Emergency Service Specialists (Servicemen) and other single person crews have mobile data terminals in their trucks. Crews do not have data terminals, but have been equipped with two-way radios and iPhones. This deployment enables transfer

[14] DR 634
[15] DR 381
[16] DR 87
[17] DR 714
[18] DR 87
[19] DR 713, DR 74

of pictures and documents. Supervisors have laptops with air cards for access to corporate applications like GIS and email.[20]

- NorthStar conducted four days of field interviewing and observation and discussed field communications at each visited location. Respondents indicated that the current situation was adequate.

13.3.8 Current work management metrics reported to LIPA are inadequate. They cover only a portion of the relevant work activity and do not include fundamental metrics such as productivity, efficiency, effectiveness, and utilization.

- The MSA performance metrics related to T&D O&M work management are the Work Plan Completion Index, Substation Demand Maintenance Backlog and Primary & Residential Underground Distribution (RUD) Cable Faults. There are other metrics associated with T&D activities, but these are measures of safety and reliability.

  - The Work Plan Completion Index, is measured as the completion of the following three components in their entirety: O&M Work Plan, Capital Work Plan, and Corporate Initiatives
  - The Demand Substation Maintenance Backlog measures the number of substation demand maintenance jobs not completed (backlogged), in priorities 1 and 2, and is measured as the number of jobs in the substation maintenance backlog at the end of each contract year.
  - Primary Cable Faults are measured as the average number of days required to return faulted primary cables to normal service. RUD Cable Faults measured as the average number of days to Residential Underground Cable faults to service. [21]

- National Grid Performance Metrics Procedure does not define the terms "units" or "jobs" used in the Work plan Completion Index and Substation Demand Maintenance Backlog [22]

- The Work Plan Completion Index, does not address large portion of the O&M work plan activity, such as public works and customer order activities. [23]

- **Exhibit 13-9** is the Work Plan Completion Index for 2011. It simply shows the planned number of units for the year, and the actual number of units. There is no definition of what work comprises a "unit."

[20] DR 384
[21] DR 629
[22] DR 629
[23] DR 381

Exhibit 13-9
2011 O&M Completion Index

Figure 9: O&M Workplan
2011

	Planned units for 2011	Actual units YTD
ESO		
PM Bulk Electric System (BES)	702	702
PM ESD Substation Emergency Restoration Radios	253	253
Inspection - Under Frequency Load Rejection Relays	75	76
SSM		
Transf/phase shifter		
Reactor & Regs IST		
In service test	480	480
Out of service test	33	33
Tap Changer Overhaul	24	27
Transmission OCB		
Overhaul and Test	21	19
Transmission Gas Circuit Brkr		
Gas Circuit Breaker Test	69	55
Switchgear/Indoor Breakers		
ACB Overhaul	104	99
OCB Overhaul	13	13
VCB Overhaul	100	100
GCB Overhaul	10	10
Swgr Inspection	29	19
Batteries		
First Half	208	208
Second Half	208	208
Pump houses	164	164
ATO	396	396
Oil test OCB's*	132	128
Thermovision		
All Substations	185	185
Network Protectors	147	115
Totals	2323	2259
Electric Service		
ATO's	50	50
ACR's	20	20
Capacitors	1558	1558
Thermography - QN/ES, System Transmission	1950	1950
Tree Trim		
Transmission Miles	200	200
Distribution Miles	1718	1718
2011 LIPA initiatives **NG Lead**	**2011 Milestones**	**2011 Status**

Several PM Activities were delayed due to hurricane Irene. These were identified to LIPA and will be completed in 2012.

Workplan Completion Index: Measured as the completion of the following three components in their entirety (subject to accidental, incidental and minor omissions): O&M Workplan, Capital Workplan and Corporate Initiatives. Prior to the beginning of each Contract Year, the parties will agree as to the O&M Workplan, the Capital Workplan and the Corporate Initiatives for such Contract Year.

O&M Workplan: the entire T&D maintenance annual plan, established each Contract Year. During the Contract Year, LIPA or the Manager, subject to LIPA's approval, may exclude certain planned maintenance activities in any particular Contract Year. However, any excluded maintenance activities will be added to the subsequent Contract Year's O&M Workplan.

Capital Workplan: the total of all scheduled capital projects and programs, established based on each Contract Year's approved budget, as adjusted from time to time by LIPA or the Manager, subject to LIPA's approval, throughout each Contract Year.

Corporate Initiatives: the completion of all corporate initiatives that are identified by the parties on an annual basis. LIPA or the Manager, subject to LIPA's approval, may exclude certain planned corporate initiative activities in any particular Contract Year. However, any excluded activities will be added to the subsequent Contract Year's Corporate Initiatives.

Source: DR 19

- LIPA's monthly tracking of Work Plan Completion provides a limited view in that it only covers the work of about 50 equivalent employees.[24]

  - Data was provided by National Grid for the MSA-required work reported under the Work Plan Completion Index.
  - The data provided includes approximate labor hours for performing all the 20 Work Plan tasks with the exception of tree trimming. The time for all these activities was the equivalent to about 45-50 Full Time Equivalents (FTEs).
  - All the work was performed by Substation (25 FTEs), Protection (6 FTE's), and Electric Service Operations (15 FTE's). This leaves a large portion of Work Plan activity unreported. [25]

13.3.9 Most position descriptions do not have identified quantitative KPIs to measure performance.

- National Grid's supervisory position descriptions are complete in terms of documenting position accountabilities, personal qualifications, and job dimensions.

- Supervisory employee position descriptions reportedly include KPIs. However, As shown in **Exhibit 13-10**, of the eight position descriptions reviewed by NorthStar, only description for Vegetation Management included any KPIs. [26]

13.3.10 National Grid uses several programs to improve the skills of its employees, but there is no focus on improving productivity.

- National Grid has an Engineering & Line Person Academy which offers 30 courses for apprentice linemen, linemen foremen and electrical mechanics. Courses address topics ranging from climbing to network protector theory.[27] National Grid is establishing a similar academy for Substations, Protection, & Telecom.

- There is a Safety Advocate program staffed by union members and regular safety meetings with action items and problem resolution.[28]

- There are a number of committees focused on workforce-related employee performance and process improvement, including the following:

  - LI T&D Switching Committee (monthly)
  - LI T&D Clearance and Control Working Group
  - Operating Procedures Committee
  - Business Continuity Planning (BCP) Committee
  - Change Agent (for communication with "critical masses"
  - Improve the Process Committee (for post-transformation processes)

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[24] DR 381, DR 620 Attachment E
[25] DR 381
[26] DR 212
[27] DR 386
[28] DR 386

- Ten Management and Union T&D committees, including work methods, safety equipment, and vehicles
- SPT and Electric Service Safety Meetings
- ESO Switching Committee
- ESO Work Methods Committee.[29]

Exhibit 13-10
Position Description Audited for the Presence of KPIs

Job Title/Department	Job Purpose/Related Information	KPI?
Coordinator OH/UG Lines Distribution Support	Manage & coordinate work requirements for the OH/UG Lines department in order to maximize field efficiencies and workforce utilization by providing a consistent progression of work to meet internal and external need dates.	No
Foreperson – Long Island Distribution Support	Oversees the management of the electric meter and test shops and dielectric testing lab for the Long Island T&D Electric Distribution organization. Employees: 10 FTEs	No
Manager, Contract Management Construction Delivery	Ensure uniform, consistent and effective management control of LIPAs labor and customer contracts. Sets policy, develops approved bid lists, and reviews technical specification and documents for constructability. Manages: 8-10 FTE Contracts administered: $50-100 million	No
Manager, Support Services Distribution Support	Responsible for all aspects of electricity work completion, as-builts, closeout, maps and records, including GIS quality control and posting services. Accountable for providing the highest level of clerical and administrative support to the Long Island T&D EDO organization and LIPA. Employees: 52 FTEs Budget: $0.5 million O&M	No
Director, Project Management Construction Delivery	To ensure that LIPA's Substation and Transmission capital projects are managed to cost and schedule as well as to National Grid's standards of safety, health, security, and quality. Manages: 8-10 FTE qualified engineering professionals O&M expense: $1.5 million project management accountability Capital expenditure accountability: approximately $300 million	No
Manager, Public Works Construction Delivery	To reduce LIPA's and National Grid's exposure, manage the relocation, support, and protection of LIPA's electric and National Grid's gas facilities associated with municipal construction projects within Long Island and New York City's Rockaway Peninsula. Annual capital budgets for relocation work: $5 million for electric work and $3 million for gas work. Municipal relationships: 124	No
Manager, Vegetation Management Construction Delivery	To optimize performance, costs, and long-term effectiveness by managing the delivery of maintenance services related to forestry, right-of-way (ROW), and grounds maintenance on the LIPA T&D system. The metric is reported in monthly Work Plan reports. Manages: 8-10 FTE plus 140-170 contract people. Projects: $15-20 million	Yes
Schedule Analyst Distribution Support/COF	Responsible for managing the customer experience for LIPA electric service requests. Charged to manage the life cycle of the work request, by proactively managing job requirements and dependencies from the point after order initiation to field completion and delivery of the first bill.	No

[29] DR 720

13.3.11 Several of National Grid's work management processes are undocumented.

- **Exhibit 13-11** summarizes National Grid's procedural documentation for processes and activities related to work management.
  - Processes are undocumented, are documented and maintained at the department level, or are documented at the corporate level.
  - Some processes rely on National Grid systems and may have to be modified to avoid disruption by the absence of access to those systems after January 1, 2014.

Exhibit 13-11
Status of Work Management Documentation

Examples of Activities (Department)	Status[30]	Comment
Process Improvement Program	Informal/Undocumented	
Procedure for Establishing Employee Requirements to Meet Workload	Informal/Undocumented	
Circuit Improvement Program	Informal/Undocumented	
Emergency Service Specialist Staffing Policies & Procedures	Informal/Undocumented	
Allowances and Contingencies	Informal/Undocumented	
Work Plan Generation Process	Informal/Undocumented	
Variance Analysis Procedure (Program Management)	Department-Generated,	Relies on National Grid systems
Change Control Process (Program Management)	Department-Generated,	
Internal versus External Sourcing (Program Management)	Department-Generated,	
Index of Long Island T&D (technical) Procedures	Department-Generated,	
Customer Order Fulfillment Process (Distribution Support)	Department-Generated,	
Electric Design & Construction Pre-Check Form & Work Expectation Form	Department-Generated,	
Distribution Construction Guideline (Construction Delivery)	Department-Generated,	
Contractor Evaluation Form (Forestry)	Department-Generated,	
Outage Service Flowchart	Department-Generated,	
LIPA Risk Scoring Job Aid	Corporate Level	
LIPA Energy Plan Status Update (Listing of Effectiveness & Efficiency Improvements in T&D)	Corporate Level	
Vegetation Management Strategy	Corporate Level	
Budget Process (Program Management)	Corporate Level	Relies on National Grid systems
Performance Metrics Procedure (Program Management)	Corporate Level	Relies on National Grid systems
GO-10106 Electric Facility Relocations for Public Works	Corporate Level	

DRs 86, 87, 88, 89, 91, 94, 117, 122, 125, 149, 184, 188, 380, 385, 625, 626, 629, 630, 631, 632, 634, 658

[30] If the process was described in the response, it was not counted as documented.

13.3.12 The management of day-to day schedules is appropriately the responsibility of Scheduling and Work Coordinators. The effectiveness of the Scheduling and Work Coordinators is diminished because they report to the central Distribution Support Department, rather than to the managers with whom they share responsibility for workforce scheduling and utilization.

- Day-to-day scheduling is the responsibility of the Scheduling & Work Coordinator. Responsibilities reportedly include:

  - Coordinating resources (internal personnel, contractors, special equipment, vehicles, tools, etc.) and satisfy job requirements (switching & clearance requests, outage coordination, markouts, flagging, tree trim, etc.).
  - Participating in weekly scheduling/construction meetings to discuss status of ongoing work and upcoming work.
  - Responsible for the adherence to the Week 0 lock down schedule and for creating, prioritizing and managing daily work crew schedules to ensure the highest priority work is being given to the crews daily.
  - Create and estimate work requests for emergency work as well as other types of work, as necessary, to ensure accurate accounting on work orders.
  - Communicate with customers in order to coordinate appointments and planned outages, as well as resolution of inquiries and any other communications that may be necessary.
  - Manage backlog of work available and develop prioritized contingency work in order to capitalize on opportunities to achieve safety, efficiency, reliability, and financial goals.[31]

- Coordinators are located on-site in the divisions, but report centrally to the Distribution Support Department.

- The coordinators work for, but don't report to, the managers to whom they are more directly responsible and with whom they share responsibility for workforce schedules, utilization, and efficiency.

- Coordinator reporting should be local, not central to the Distribution Support Department. Distribution Support is not directly responsible for workforce productivity.

13.3.13 National Grid has sound processes in place to review crew practices, and has exceeded LIPA's goals for safety performance.

- National Grid performs Compliance Assessment evaluations of crew performance.[32]

  - The Compliance Assessment is an eight page quality form for onsite review of crew practices.

[31] DR 212 Position Description
[32] DR 627

- The form contains 159 evaluation factors and addresses manual handling, communication and risk assessment, work zone safety, excavation, work methods and other field observations.[33]

- LIPA goals for safety performance are exceeded.[34]

13.3.14 While National Grid appropriately uses open stockrooms for frequently used material, the staging of materials for work orders is disorganized.

- Open stockrooms for frequently-used material is generally accepted good practice that is cost effective in reducing crew delays.

- NorthStar assessed the staging of project materials at the Hicksville loading dock and found:

  - Material for individual projects is not clearly labeled
  - Materials were disorganized.
  - There was a lack of dedicated racks and adjacent large item lay down areas.[35]

13.3.15 Plans for the workforce transition include identifying key personnel and hiring requirements in order to implement an asset management system.

- The PSEG-LI workforce transition plan identifies "key leadership positions" in T&D. Filling the positions is important "to the continued and effective operation of the 1200+ T&D organization as well as leading the change to an asset management model." The positions include the following: Director Overhead Services, Director Underground Services, Director Projects & Construction, Director Asset Management, Director Operations, Director Substation & Telecommunications, and Director, Energy Efficiency & Renewable Energy.[36]

- T&D Operations will require few additional position external hires (4.3 equivalent staff split about evenly between union and non-union positions).[37]

- The ServCo organization in T&D will be restructured.

13.3.16 National Grid does not have an adequate succession plan for key positions.

- A succession plan was unavailable. Comparable plans identify longer term short falls in critical positions and contain actions for closing those gaps.[38]

- Succession plans should address expected gaps in critical represented and exempt positions. Other utilities have a stable senior workforce, many of whom are near

[33] DR 627
[34] DR 6
[35] IR 131-134
[36] DR 210 Workforce Transition Plan, page 13
[37] Ibid.
[38] DR 721

retirement age. Also, apprentice program for technical staff can be five years, adding urgency to forward planning for replacements.

13.4 Recommendations

13.4.1 Develop an integrated work management system that formalizes planned work, support requirements, and provides continuous feedback on workforce effectiveness.

The system should be in an easy-to-use format expressed in manhours, along with the combined employee and contractor capacity available to perform the work, supported by real time reporting of capacity utilization. The system should include:

- Documentation of histogram development and Work Plan process.
- Enhanced methods to calculate workforce capacity and utilization.
- Expanded workforce coverage in reports.
- Documentation of processes for establishing serviceman workforce levels.
- Documentation of criteria for adding contractor capacity.
- Establish real time variance reporting for project costs.
- Additional decision-making information to Work Plans.

13.4.2 Fill gaps in the current management information reporting and organizational reporting relationships to support an integrated work management system.

Options that should be considered in planning for an integrated asset management approach and work management related processes, organization and software include: pursuing a manual system in the near or long term, adapting current systems and procedures, or converting to new incoming systems and procedures.

Elements of an integrated plan should include:

- Change Coordinator reporting relationship.
- Improved project materials visibility and ease of location.
- Add KPIs to position descriptions.
- Review the design of monitoring and controlling reports to improve their usefulness and add KPIs.
- Prepare a roadmap for migration from existing information systems to new systems.
- Further review reporting relationships, scope, and location for support functions.
- Prepare a succession plan for key positions.

14. CUSTOMER SERVICE

This chapter addresses the customer service functions provided by LIPA and National Grid for the LIPA customers.

14.1 Background

New York utility operations are governed by Section 16 of the New York Codes, Rules and Regulations (NYCRR). Part 11 of Section 16, also known as the Home Energy Fair Practices Act (HEFPA), was enacted in 1981 to provide residential customers protection in the areas of services, billing and payment procedures. (Part 13 establishes rules governing the provision of service to nonresidential customers, similar, but not identical, to the residential rules in HEFPA). HEFPA sets forth specific utility and energy service company (ESCO) requirements governing the provision of service, including:[1]

- Application for residential service, including requirements for written applications, denials of service, and timelines for initiation of service
- Deposits, late payment and other charges, and deferred payment arrangements
- Meter reading and billing, including estimated bills, back billing and budget billing
- Bill content and notification requirements
- Termination, disconnection and suspension of service, including cold weather provisions
- Procedures for cases involving medical emergencies, elderly, blind, disabled, financial hardship and heat-related customers
- Service to two-family and multiple dwellings.

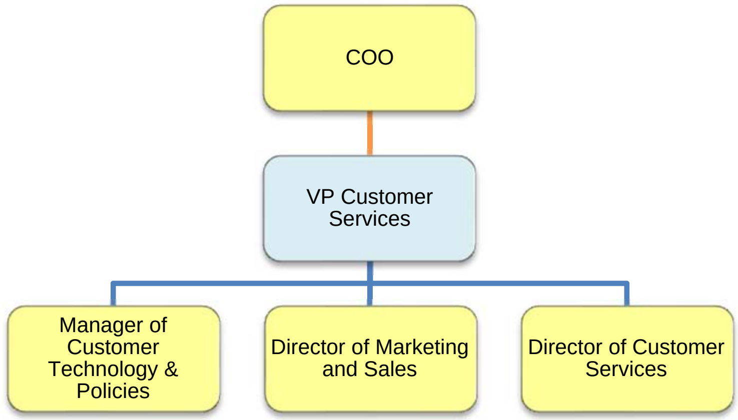
NYCRR §§ 11.20 and Part 12 address customer complaints.

The majority of the customer service functions for LIPA electric customers are performed by National Grid. National Grid reads and tests customer meters; prepares and submits costumer bills; reviews billing exceptions; performs payment processing, back office and field collections; processes customer requests for turn-ons, turn-offs, and new service; conducts high bill investigations; responds to customer outages; investigates potential theft of service and unmetered service; and staffs the call center and customer offices. The majority of these functions are performed jointly for both LIPA electric and National Grid gas. LIPA monitors National Grid's performance on a monthly and sometimes daily basis, providing feedback as necessary to address issues as they arise.

Prior to the departure of the Vice President of Customer Services at the end of 2012, the LIPA customer service functions reported through that officer directly to the COO, as shown in **Exhibit 14-1**.

[1] "Home Energy Fair Practices Act, Rules Governing the Provision of Gas, Electric and Steam Service to Residential Customers (incorporating amendments from the Energy Consumer Protection Act of 2002), New York State Public Service Commission, http://www.dps.ny.gov/HEFPA_Brochure_12-08.pdf

Exhibit 14-1
LIPA Customer Operations Organization – 2012

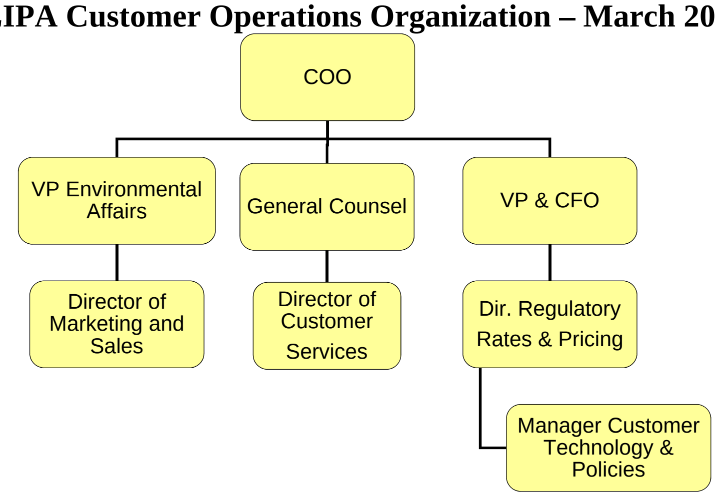


Note: Blue denotes position that became vacant upon the resignation of the incumbent in late 2012 and has not been filled.
Source: DR 1.

- LIPA's Marketing and Sales organization handles the marketing and advertising of LIPA's products and programs, including customer communications. It also interfaces with National Grid's major account executives (MAE) who serve as the primary point of contact for 585 of LIPA's large customers.
- LIPA's Customer Services organization monitors National Grid's customer service function and processes complaints received by LIPA. LIPA's Customer Services organization is responsible for answering customer calls/correspondence and resolving over 700 customer complaints annually.

With the departure of the Vice President Customer Services, the customer operations functions were split as shown in **Exhibit 14-2**.

Exhibit 14-2
LIPA Customer Operations Organization – March 2013

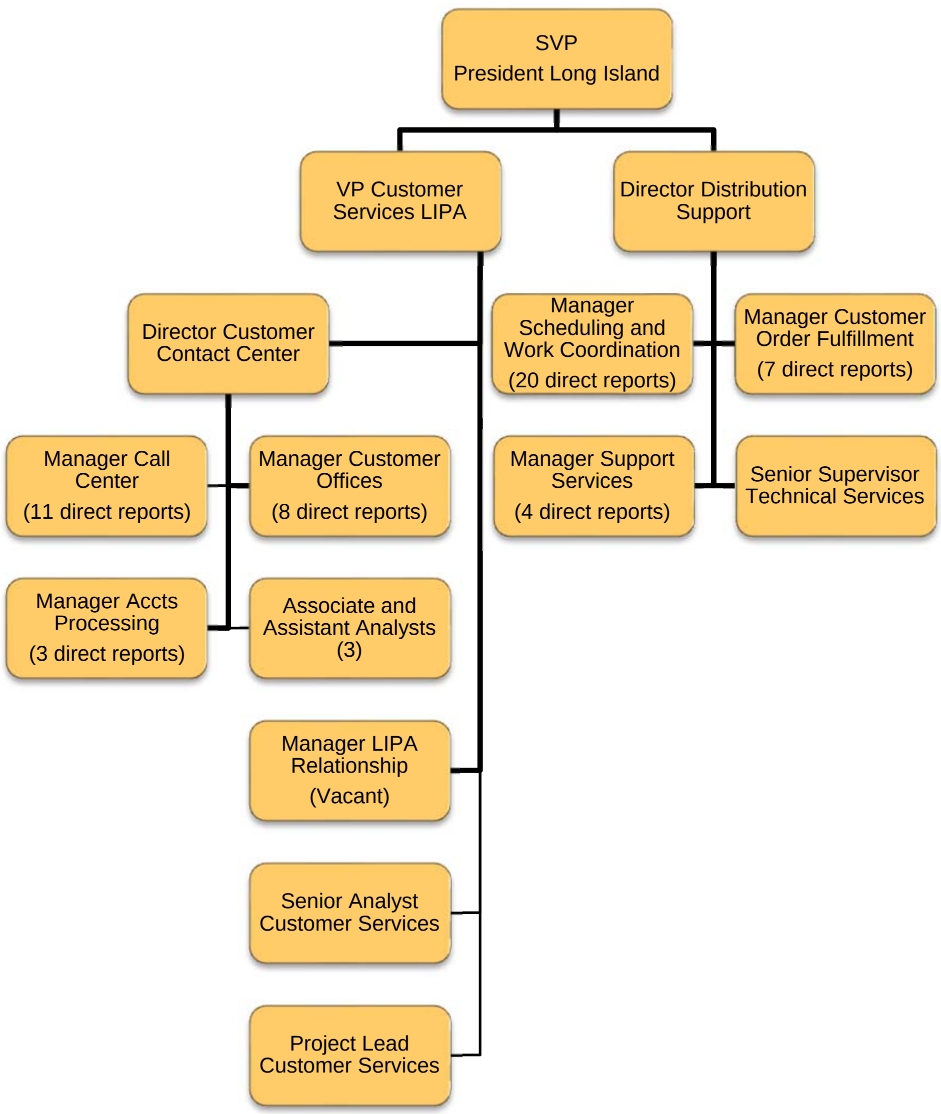


Source: DR 1.

National Grid's Long Island Customer Operations organization is depicted in **Exhibit 14-3**. The Call Center and Customer Order Fulfillment both ultimately report to the SVP/President of Long Island. LIPA receives Major Accounts and Economic Development services and other customer operations support functions, such as billing, payment processing and portions of credit and collections, through various National Grid functional groups that service all of National Grid's US utilities. The customer operations support functions are geographically separate from National Grid's Long Island operations.

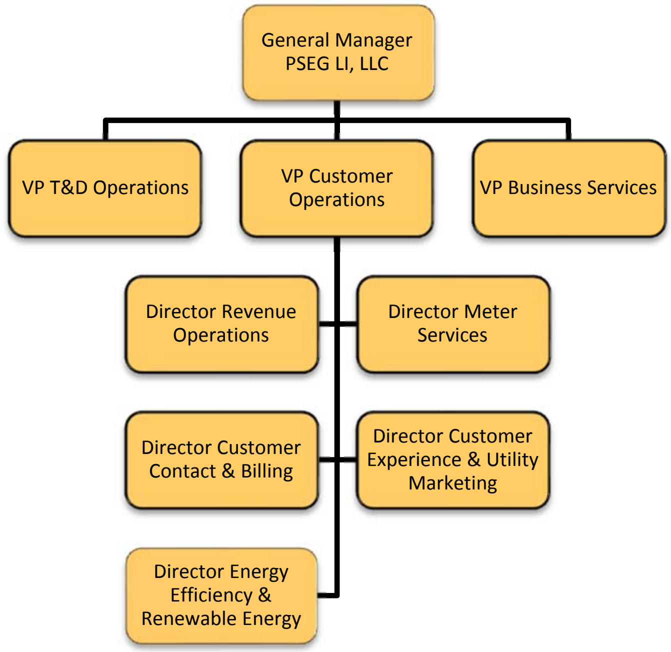
The proposed PSEG-LI organization will consolidate the customer service functions under a Vice President Customer Operations who will report to the General Manager of the ManageCo as shown in **Exhibit 14-4**.

Exhibit 14-3
National Grid Customer Operations
(serves both Long Island gas and LIPA electric customers)



Source: DR 2 and DR 210.

Exhibit 14-4
Proposed PSEG-LI Customer Operations Organization Structure



Source: DR 2 and DR 29.

Meter Reading and Billing

Utility customer billing has three basic steps – m meter reading, bill calculation and bill printing. These steps are time sensitive processes and are performed according to the following schedule for LIPA customers.

Day 1 – Meter Read
Day 2 – Read Verification
Day 3 – Mail Bill/Day 6 for Green Choice Customers
Day 26 – Payment Due Date.[2]

While most LIPA customers (83 percent) receive monthly bills, the majority of LIPA's meters are read on a bi-monthly basis by National Grid meter readers who walk the routes and do manual meter reads.[3] Less than 1 percent of LIPA's of LIPA meters are read via encoder receiver transmitters (ERT) as part of the pedestrian read routes or via automated meter reading (AMR) technology.[4] LIPA is in the process of migrating approximately 7,500 of the existing manually read meters to an Advanced Metering Infrastructure solution.[5]

Meter readers read both LIPA's electric meters and National Grid Gas' Long Island gas meters at the same time. Twenty cycles are read each month where approximately 1/40th

[2] DR 113
[3] Commercial demand, service classification 2-MRP, and special customer request meters are read monthly
[4] 22,000 ERT/Walk-by AMR and approximately 2,500 AMR/MV90 (DR 505)
[5] DR 505

(27,500) of the customer meters are read. About 17 percent of LIPA's customers are read bi-monthly and billed bi-monthly (195,315 out of 1,158,314 meters). The remainder of bi-monthly read customers receive an estimated bill every other month. Just over 78,000 meters are read monthly. Forty-three percent of LIPA's customers are on balanced billing, wherein estimated annual usage is divided into twelve monthly payments.

Exhibit 14-5 provides details on LIPA's meter reading and billing process.

Exhibit 14-5
Meter Read and Billing Frequency

	Monthly Billed			Bi-Monthly Read and Billed	Total
	Monthly Read	Bi-Monthly Read	Subtotal		
Residential					
Balanced Billing	22,007	463,619	485,626	0	485,626
Usage-Based Billing	33,760	338,564	372,324	172,489	544,813
Subtotal	**55,767**	**802,183**	**857,950**	**172,489**	**1,030,439**
Commercial					
Balanced Billing	3,243	3,635	6,878	0	6,878
Usage-Based Billing	19,477	78,694	98,171	22,826	120,997
Subtotal	**22,720**	**82,329**	**105,049**	**22,826**	**127,875**
Combined					
Balanced Billing	25,250	467,254	492,504	0	492,504
Usage-Based Billing	53,237	417,258	470,495	195,315	665,810
Total	**78,487**	**884,512**	**962,999**	**195,315**	**1,158,314**

Source: DR 506

The Customer Accounting System (CAS) and the Enhanced Billing Option (EBO) function as LIPA's customer information and billing system. CAS is a custom, homegrown mainframe application developed in 1975 which has been modified over time to increase functionality and address user requirements. CAS provides meter reading, reporting, bill/usage calculations, credit and collections, service order processes and marketer support. EBO was implemented in 2001 to ensure compliance with the NYPSC's Uniform Business Practices and Single Bill Orders for ESCOs and Utilities.[6]

The vast majority of LIPA's bills are produced using a batch process. As part of the controls associated with this process, the system generates approximately 20,000 to 25,000 billing exceptions each month. Exceptions may be informational or may require manual adjustment to ensure the accuracy of the bill. Examples include a possible stopped meter, actual demand less than estimated demand and negative use. Billing exceptions are investigated by National Grid personnel. Most result in the bill being released for billing. Others may require a re-read of the meter or other investigation.

Approximately 18,000 of LIPA's accounts must be billed manually because they involve non-standard rates or other special contract or tariff conditions, and decisions were made not

[6] April 25, 2013 Customer Accounting System (CAS) Technical Evaluation (DR 416)

to program them into EBO/CAS. The manually billed accounts include those on renewable net metering and economic development rates. **Exhibit 14-6** provides details of these accounts. For these customers, bills are generally calculated off-line, using spreadsheets, in accordance with procedures established for each account type.[7] The majority are then entered into CAS for revenue purposes. The customer receives the manual bill which resembles the LIPA bill. A handful of customers receive bills outside of CAS and are processed through LIPA's accounts payable as "Cycle 21."[8]

Exhibit 14-6
Manual/Special Billing Accounts

Type	Number of Accounts	Monthly Billing Time Frame	Offline billed	Billed through CAS	Revenue pushed through CAS
Subtractive Metering - Electric (LIPA Impact)	2	Ongoing, based on cycle read	Yes	No	Yes
Commercial Net Metering	8	Ongoing, based on cycle read	Yes	No	Yes
Residential Net Metering (MRP 1, Group 1)	9	Ongoing, based on cycle read	Yes	No	Yes
RECHARGE NY	145	Completed and sent to NYPA by the 10th of the month	Yes	No	Yes
Co-Generation SC-12	16	Completed by the 2nd week of the month	Yes	Yes	Yes
Hofstra Co-Generation	1	Completed by the 2nd week of the month	Yes	Yes	Yes
Economic Development/Bus. Development Rate	140	Completed the 2nd week of the month	No	Yes	Yes
SC-13 (Special Contracts)	7	By Cycle	Yes	Yes	Yes
Brookhaven National Lab	2	Completed by 3rd week of the month	No	Yes	Yes
BNL Hydro	1	Completed by first week of month	Yes	No	No
NYC Street Lighting	1		Yes	No	Yes
Street Lighting Billing	2,050	1st of the month	No	Yes	Yes
Traffic Signal Billing Maintenance	9,080	Completed monthly by Run 19	No	Yes	Yes
NYC Cost Savings Program	5	Ongoing	No	Yes	Yes
Franchise Billing	10	Monthly by cycle	Yes	No	Yes
EUGOBOS – Company Books	1,167	Ongoing, based on cycle read. 2 with company books	Yes		
Dusk to Dawn	6,113	Completed by the 20th	No	Yes	Yes
Total	**18,757**				

Source: DR 619

Contact Center and Customer Offices

National Grid staffs a call center located Melville, New York, which handles both LIPA electric and National Grid Gas calls. Although LIPA Residential, LIPA Business and

[7] IR 118, DR 683
[8] DR 682. There are 20 meter reading cycles. Cycle 21 is used for these accounts handled outside the normal process.

National Grid Gas customers are each provided with different phone numbers, all calls are routed to the Melville call center. Call center representatives (Customer Service Representatives (CSRs)) can handle either gas or electric calls. The call center operates 24/7 for emergency and service-related calls. Billing and general inquiry calls are taken from 8:00 am to 8:00 pm, Monday through Friday. Peak staffing is about 120 representatives. In addition to inbound calls, the call center also handles outbound collections calls.

National Grid currently maintains 11 walk-in customer offices for both electric and gas customers, with an additional LIPA-only office being added in The Rockaways.[9] The customer offices perform similar activities as the call center, but also accept payments, handle income verification for certain of the limited income programs and take commercial applications.

Complaints

LIPA customers have a number of channels available to them to register complaints regarding the quality and cost of their electric service.

- National Grid handles the majority of the routine customer complaints and inquiries through the call center and customer offices. Customers who do not feel their concern or issue has been adequately addressed can escalate the issue to National Grid management at the call center and customer offices.

- Customers may phone, email or write LIPA directly to resolve their issue initially or may file a complaint with LIPA after an unfavorable decision is rendered by National Grid. In general, customers are encouraged to first contact National Grid to try to resolve their complaint. Complaints received by LIPA are reviewed by the LIPA Customer Services organization, which currently reports to the General Counsel.

- Customers may file a complaint with the Utility Intervention Unit of the Division of Consumer Protection, New York Department of State (UIU). The UIU will initiate a complaint and forward it to LIPA for investigation. Upon LIPA's decision, both the customer and the UIU will be notified of the outcome.[10]

Customer complaints submitted to LIPA's executive office are received by LIPA's Customer Service organization and logged into a MS Access® database for tracking purposes. **Exhibit 14-7** provides the sources of complaints processed by LIPA from 2007 through June 12, 2013. These counts do not include complaints or calls received directly by National Grid. Historically, the most common sources of complaints were letters and telephone calls. However the UIU began submitting complaints on behalf of customers in 2012, and these represent a growing share of the complaints.

[9] IR 35

[10] http://www.dos.ny.gov/consumerprotection/

Exhibit 14-7
Sources of Complaints

Source	2007	2008	2009	2010	2011	2012	2013 (thru 6/12)	Total
UIU						97	143	240
E-mail	4	5	7	16	21	31	5	89
Fax	4	8	4	1	5	6	1	29
Interview	1	1	2	1	2	3		10
Letter	110	74	58	89	137	139	71	678
Other	2	3		2	2	34	5	48
Third Party	37	59	59	207	220	110	47	739
Telephone	332	319	346	479	445	350	159	2,430
Total	**490**	**469**	**476**	**795**	**832**	**770**	**431**	**4,263**

Source: DR 623

LIPA reviews the complaint, determines the appropriate action and advises National Grid's Customer Satisfaction and Regulatory Compliance (CSRC) group. Some complaints may be resolved directly by LIPA. For others, LIPA may determine a proposed resolution and direct National Grid to implement it, or may require further investigation by National Grid. For those directed to National Grid, LIPA is advised of the resolution. Once a case has been resolved, the database is updated, the customer is contacted and the case is closed.

For tracking purposes, LIPA classifies complaints it receives as either "initial" or "escalated" (hereafter referred to as LIPA Initial Complaint or LIPA Escalated Complaint for clarity) in an effort to mirror NYS Investor-Owned Utility (IOU) reporting requirements. A LIPA Initial Complaint is one which has been submitted to LIPA for the first time. A LIPA Escalated Complaint is a complaint which has been received for the second time. As an example, assume a customer has contacted LIPA regarding a high bill complaint (LIPA Initial Complaint) and LIPA sent out someone from National Grid to perform a high bill investigation and meter test which demonstrates the meter is working correctly. If the customer is still not satisfied and contacts LIPA again, it would be logged as a LIPA Escalated Complaint. National Grid provides reports to LIPA that track these complaints. National Grid internally may use the term escalated complaint to refer to complaints to the call center which are escalated to a supervisor within the call center for resolution. Hereafter, these will be referred to as National Grid Escalated Complaints.

Hurricane Sandy

Hurricane Sandy has, and will continue to have, a significant effect on customer operations. As people were pulled from their normal jobs to perform storm duties, a number of activities were delayed or were not performed, resulting in backlogs and impacts to customers as well as LIPA. In particular:

- Meter reading was suspended from the storm until November 26, 2012, resulting in an increase in the number of estimated bills.[11]

- Individuals in the Accounts Processing group were pulled in to assist the call center, resulting in a backlog in the investigation of billing exceptions and high bill complaints. As of April 2013, the average customer wait time for a billing investigation was approximately three weeks.[12]

- Overtime has been approved in a number of areas to address Sandy-related backlogs, resulting in higher costs.

- Initially, bills were held for 38 zip codes (approximately 260,000 accounts).[13] As of May 8, 2013, some accounts in six zip codes.

- Collections is seeing the effects of the billing and collections holds in its delinquency numbers; there is concern about the potentially significant impact of large, multi-month bills on the financial viability of small commercial customers. Collections activity stopped and did not resume until February 1, 2013.[14]

- LIPA credited all customers with a 14-day basic service delivery charge and waived a number of fees, with resulting financial impacts on the Authority. [15]

- Call center call volumes continue to be higher than normal through May 2013, resulting in even higher than normal wait times.

- Customer dissatisfaction has risen.

14.2 Evaluative Criteria

- Does LIPA have processes and systems for analyzing and reflecting feedback from customers?
- Does LIPA receive adequate information regarding customer complaints and service levels from National Grid and will this continue with the transition to PSEG?
- Does LIPA have a formalized process to handle customer complaints and inquiries that have not been resolved by its MSA provider, or pending OSA vendor, and the DCP?
- Does LIPA monitor the level and nature of both internal and external customer complaints?
- Does LIPA appropriately balance service levels and customer service staffing levels/ costs?
- Do customers receive accurate and timely bills?

[11] DR 488
[12] Customer Meter Services Monthly Operating Report, Month End April 2013, provided during monthly meeting
[13] DR 488 and clarification email
[14] April 2013 Billing Operations report provided during IR 153
[15] DR 488

- Does LIPA provide its customers with accurate and timely information regarding service times, service request or customer inquiry status, outages and estimated service restoration times?
- Are existing customer information and customer accounting systems used to support customer service operations efficient and effective?
- Do customer systems adequately support LIPA's technical business needs and processes, compliance with state laws and regulations, and the achievement of customer service goals?
- Do appropriate interfaces existing between customer systems and other LIPA systems and external service providers?

14.3 Findings and Conclusions

14.3.1 With the Departure of the LIPA VP of Customer Services, customer service functions are distributed across the LIPA organization with no one person acting as the "voice of the customer".

- The former LIPA VP of Customer Service was the driver behind a number of initiatives aimed at improving customer service including the development of annual customer services strategic plans, the Customer Satisfaction Improvement Program (CSIP), and monthly operational reporting requirements.

- With the departure of LIPA's VP of Customer Services, the customer service functions were split between Environmental Affairs, the General Counsel and Regulatory, Rates And Pricing (under the CFO), thus losing specific Executive level focus.

- This organizational change reduces the visibility of customer service and makes coordination and communication among the business units responsible for customer service functions more challenging.

- When asked in interviews, LIPA personnel provided a variety of names for the person who represents the "voice of the customer" in decisions at the executive level. This indicates confusion within the organization as to who actually speaks for the customer or assures appropriate attention and focus on serving the needs of the customer.

14.3.2 LIPA suffers from significant perception and customer satisfaction issues. Overall, LIPA's customer satisfaction is extremely poor; contact-based satisfaction levels are generally better.

- LIPA participates in two customer satisfaction-based surveys. It participates in the JD Power Utility Customer Satisfaction survey and National Grid conducts a survey of customers that have had recent contact with a National Grid employee regarding the level service (referred to as the "contactor" survey). Performance on both surveys is included in the MSA metrics.

- During the period from 2007 through 2012, National Grid's MSA Customer Satisfaction Index performance fell into the penalty range twice as shown in **Exhibit 14-8**. In 2012, data during the storm season was not used due to force majeure.

Exhibit 14-8
Customer Satisfaction Index Performance
(Percent Satisfied)

Year	Target	Performance	Performance Result [Note 1]	Source
2007	80.03	74.30	Penalty	Contactor Survey
2008	81.88	76.66	Penalty	Contactor Survey
2009	84.88	86.85	Offset	Contactor Survey
2010	87.30	87.10	Target	Contactor Survey and JD Power
2011	87.37 Note 2	86.85	Target	Contactor Survey and JD Power
2012	88.49	86.70	Target Note 3	Contactor Survey and JD Power

Note 1: Performance below target, but above the penalty is considered to have achieved the target.
Note 2: Changed mid-year from 86.60 to 87.93. Number above represents the average.
Note 3: Excludes data from October – December 2012 due to Sandy force majeure.
Source: DR 108, annual performance calculated as average of monthly survey results.

- LIPA generally ranks in the fourth quartile in JD Power customer satisfaction as shown in **Exhibit 14-9.** The 2012 JD Power Residential and Business Customer Satisfaction Surveys ranked LIPA in the fourth quartile of performance in almost all categories. In no category was LIPA's performance better than third quartile in 2012.[16]

Exhibit 14-9
JD Power Survey Results

	2010		**2011**		**2012**			
Total Industry Rankings	**Bus**	**Res**	**Bus**	**Res**	**Business**		**Residential**	
					Wave 1	Wave 2	Wave 1	Wave 2
Overall Customer Satisfaction	Q4 (last)	Q4	Q3	Q4	Q4	Q4	Q4	Q4 (last)
Power Quality & Reliability	Q4 (last)	Q4	Q3	Q4	Q4	Q4	Q4	Q4
Billing & Payment	Q3	Q4	Q4	Q4	Q4	Q4	Q4 (last)	Q4 (last)
Price	Q4	Q4	Low Q2	Q4	Q4	Q4	Q4	Q4 (last)
Customer Service	Q4	Q4	Q2	Q3	Q3	Q4	Q3	Q4

Source: DR 114 and DR 436.

[16] DRs 114 and 115.

- A recent American Customer Satisfaction Index (ACSI) customer satisfaction survey ranked LIPA worst in customer satisfaction despite an overall increase in utility customer satisfaction. The ACSI press release indicated: "What really stands out, however, is the torrential 26 percent customer satisfaction deterioration of [LIPA] due to the utility's handling of the destruction wrought by Hurricane Sandy. The ACSI loss plunges LIPA down to 43 - the lowest customer satisfaction score ever recorded for any company in any industry in the [ACSI]." [17]

- LIPA performs better in the post-contact surveys. In 2012, 86.7 percent of customers surveyed were satisfied as determined by a ranking of 6 or higher on a scale from 1-10. [18]

14.3.3 LIPA and National Grid have undertaken a number of initiatives to improve customer service levels directed towards improving customer satisfaction. Despite these efforts, issues persist.

- Each year from 2010 through 2012, LIPA developed Customer Services Strategic Plans which included situation analyses, identified key customer service objectives and developed strategies and initiatives for improving customer service.[19] The strategic plans identify a number of performance deficiencies and opportunities for improvement.

- As a result of LIPA concerns in the 2010 to 2011 time frame regarding National Grid's performance, a National Grid VP Customer Services LIPA position located on Long Island was added, the Call Center Director was replaced, and detailed operational reporting was implemented which included service level targets for a number of areas.[20]

- In late 2011, LIPA and National Grid conducted a "deep dive" of the Contactor and JD Power Surveys in an attempt to better understand key drivers of JD Power's Customer Satisfaction scores and identify options for how LIPA might mitigate them. Key customer issues identified as part of the analysis included price concerns, a greater need for communication, credit card payments and community involvement.[21]

- Based on the results of the review, LIPA created a two-part strategy: a customer service action plan referred to as "CSAT" designed to address the six main Customer Service drivers that LIPA could affect; and the separate CSIP, designed to address those drivers that were the responsibility of both National Grid and LIPA.[22]

- In late 2011, LIPA began implementing the plans for the CSAT items.

[17] http://www.theacsi.org/media-resources/press-release-april-2013
[18] DR 412
[19] With the departure of the VP Customer Services a strategic plan for 2013 was not developed.
[20] DR 40
[21] Various interviews, DR 40. As of June 2013, the implementation of credit card payments was in process and scheduled for completion in 2013
[22] IR 137, IR 168

- CSIP was initiated in late-2011 and action plans were developed in mid-2012. The objectives of the CSIP were to: manage activities to improve the customer's opinion of the services received; consolidate activities of similar purpose to provide focus; and, raise employee awareness of the importance of a customer-focused culture.[23] Initiatives addressed the escalated complaint processes, contact center operations, (reducing hand-offs), billing operations, special billing and billing exceptions, meter services, storm and external communications, media relations, rates and tariffs, and culture change. [24]

- A number of issues identified in the 2010 and 2011 strategic plans persist:

  - Key issues identified in 2010 included billing errors, customer discomfort with estimated meter reads, order fulfillment errors and a lack of customer understanding bill drivers and rate options. Concerns regarding a lack of commitment on the part of National Grid were also raised.
  - The need for new and expanded payment options was included in the 2010 strategic plan, but the capability was not developed until 2013.[25]
  - Customer satisfaction as measured by JD Power and other perception-based surveys continues to be low or declining.

- Three "Six Sigma" initiatives affecting customer service operations were undertaken by National Grid; however, these projects were discontinued as Six Sigma initiatives due to competing demands on resources and reallocation to other priority projects.[26] Two of the initiatives continued outside of the Six Sigma framework. The initiatives were: larger commercial customer billing improvements (scope reduced 3/15/12); elimination of incorrect customer refunds (continued); and the elimination of inaccurate or missing Long Island Railroad (LIRR) bills (continued).

14.3.4 The customer service function suffers from a lack of detailed analytics.

- Largely as a result of CAS system constraints, National Grid and LIPA are more able to obtain production data (i.e., monthly activity-based information) rather than perform more complex queries which would allow them to identify trends or causal drivers.[27]

- National Grid is unable to determine what portion of the theft of service cases prosecuted result in payments. National Grid can provide the number of unmetered service claims processed in a month but cannot follow these cases through the process from a data and analytics standpoint.

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[23] DR 419
[24] DR 40 and 419
[25] As of June 2013, the credit card payment option was under development, but had not yet been implemented.
[26] DR 431. According to National Grid some have been incorporated into regular business practices or different process improvements.
[27] Various interviews and attempts to obtain DR information.

- National Grid does not track the overall effectiveness of its outbound collections dialing campaign from a dollar standpoint or determine whether different call times are more effective.

14.3.5 While LIPA has a number of processes and systems for analyzing and reflecting feedback from customers, improvements are warranted.

- The JD Power surveys contain a large amount of information regarding customer concerns and responses to detailed questions underlying the aggregate results. While the results were used as part of a concerted effort in 2010 to improve customer satisfaction, it is unclear that this information is used on an ongoing basis by either National Grid or LIPA.

- In the post-contact survey conducted for National Grid as part of the MSA metrics, the definition of "satisfactory" performance is fairly broad. Respondents are asked to rank LIPA on a scale from 1 to 10. A score of 6-10 is considered satisfactory performance.[28] Reporting performance in two categories (satisfied (6-10) and very satisfied (8-10)) would provide LIPA with a better understanding of customer satisfaction levels.

- LIPA and National Grid have periodically conducted surveys of customer satisfaction with other LIPA programs and services including tree trimming, major accounts (discontinued), energy efficiency and electric service.[29]

- Complaints received by LIPA are logged and tracked within an MS Access® database developed for this purpose.[30] The data base identifies complaints received by LIPA's Customer Service Department and those forwarded from parties outside of LIPA.[31]

- LIPA receives no reports or information on the general nature of calls or complaints to the contact center. National Grid does not track complaint calls that are resolved by the CSRs, but does track complaints escalated to a National Grid supervisor. According to National Grid, this information is not provided to LIPA, and LIPA has not requested it.

14.3.6 In a number of areas, service level standards and/or actual service levels, are below industry standards and/or do not promote good customer service.

- Currently, LIPA's JD Power customer satisfaction ranking represent fourth quartile performance. National Grid achieves its target by not being almost dead last. The residential penalty trigger is 16th out of 17 or below. The commercial penalty trigger is 22nd out of 23 or below.

[28] NorthStar Analysis, DR 114/115
[29] DR 114/115
[30] Review of database
[31] DR 623

- The current average speed of answer ASA target is substantially below industry standards. Preliminary analysis indicates that raising the standard would have a limited effect on operating costs.

  - The MSA includes an ASA performance target of 168 seconds (almost 3 minutes) and a call answer rate target of 93.5 percent.[32] The ASA is an annual rather than monthly target. To achieve this standard, National Grid staffs to a service level target of 35 percent of calls answered in less than 30 seconds[33] which is substantially below industry standards. Based on NorthStar's experience, utilities typically use a service level target of about 80 percent of calls answered within 30 to 60 seconds. As examples:

    1. The Pennsylvania Commission requires all gas and electric utilities to report ASA and abandon rate statistics. **Exhibit 14-10** provides the electric utility data for 2011.[34]
    2. In 2012, Massachusetts utilities NSTAR Electric Company and Western Massachusetts Electric Company answered 86.1 percent and 92.1 percent of calls within 20 seconds. [35]
    3. PSE&G (NJ) and Elizabethtown Gas use a benchmark of 80 percent of calls answered within 30 seconds. [36]

Exhibit 14-10
Pennsylvania Electric Utility Call Answer Performance – 2011
(Percent)

Utility	ASA (percent within 30 seconds)	Abandon Rate (percent)
Duquesne	76	3
West Penn	62	5
PPL	82	3
UGI-Electric	82	4
PECO	80	5
First Energy	80	3

Source: "Customer Service Performance Report Pennsylvania Electric & Natural Gas Distribution Companies", 2011", Pennsylvania Public Utilities Commission.

[32] Amended and Restated MSA.
[33] DR 106
[34] Abandon rate refers to the percent of calls that disconnect after entering the queue to hold for a CSR. Busy out rate refers to the percentage of calls for which customers receive a busy signal and are not able to reach the call center.
[35] Massachusetts Department of Public Utilities, Docket #13-SQ-13, NSTAR Electric Company's Annual Service Quality Report, 12/31/12, pp. 5, 7-8, and Massachusetts Department of Public Utilities, Docket #13-SQ-14, Western Massachusetts Electric Company's Annual Service Quality Report, 12/31/12, pp. 9, 15-16.
[36] State of New Jersey, Board of Public Utilities, Docket #GR09050422, 5/26/2010, Attachment B and Audit of Affiliated Transactions and Management Audit of Elizabethtown Gas, The Liberty Consulting Group, 1/4/2010, p. 167.

4. The Ohio Administrative Code requires that each electric utility's average (arithmetic mean) answer time not exceed 90 seconds.
5. National Grid uses more aggressive standards in its other service territories.[37]

- At NorthStar's request, National Grid compared the FTE needed to achieve the current service level standard (35 percent of calls within 30 seconds) versus a more typical standard (70 percent within 30 seconds). The current standard requires 117 FTE; the improved standard requires 122 FTE, a difference of 5 FTE. Assuming a fully-loaded cost of $28-30 per hour, this amounts to an annual increase of $291,200 to $312,000.[38]

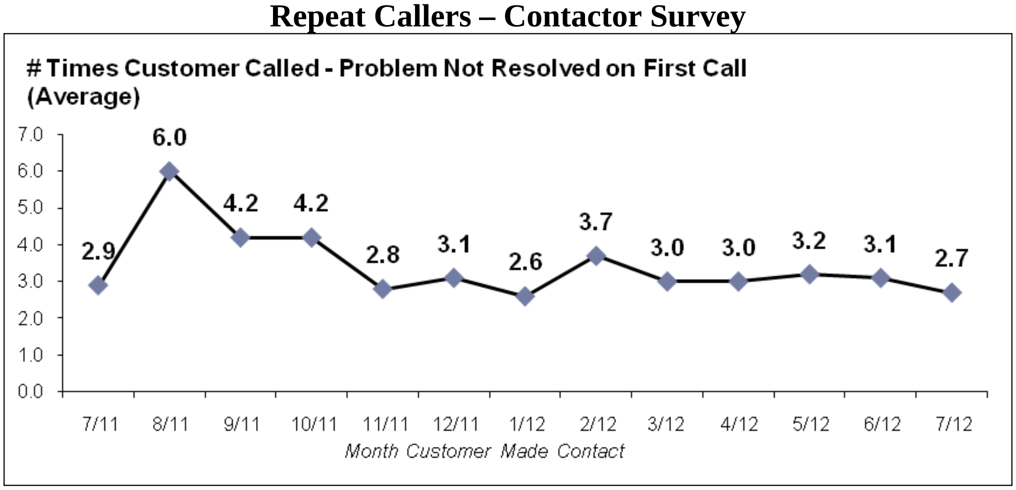
- According to National Grid, it suggested to LIPA that it would be easier to manage the call center to a higher standard, but no change was made.[39]

- LIPA's answer rate target is 93.5 percent (including calls answered by the IVR). Answer rate is the reverse of abandon rate. LIPA's abandon rate target is effectively 6.5 percent (penalty 8.5 percent and offset 4.5 percent).[40] The Pennsylvania utility abandon rates range from 3 to 5 percent, as shown in Exhibit 14-10.

- A discussion of the meter reading standard is provided in Conclusion 14.3.14, below.

- **Exhibit 14-11** provides the numbers of repeat callers to the contact center to resolve an issue based on the contactor survey. This does not include the calls that are escalated to a supervisor and resolved at the time. Based on these results, a customer must contact National Grid about three times to get an issue resolved.

Exhibit 14-11
Repeat Callers – Contactor Survey



Source: DR 114

[37] IR 154
[38] DR 661, NorthStar rate estimate
[39] Various interviews
[40] DR 109

- Based on National Grid's procedures, it is possible for a customer with an escalated complaint to have to talk to four or five National Grid employees before being directed to LIPA. National Grid's contact center escalated complaint/appeals process allows the customer to escalate/appeal to a Contact Center Supervisor, a Senior Supervisor or the Call Center Manager. Complaints that go beyond the Manager get forwarded to either LIPA or Customer Satisfaction & Regulatory Compliance.[41] The customer office appeals process requires National Grid to escalate complaints to a Supervisor, Manager and then Customer Satisfaction & Regulatory Compliance.[42]

- National Grid and LIPA have appropriately agreed to a number of service level requirements in addition to the MSA metrics (examples provided below); however, in some cases the targets are too low.

  - Standards for processing demand exceptions (five billing cycles) and for Service Classification No. 2-Multiple Rate Period (2-MRP" or "MRPII) exceptions (two billing cycles).
  - Targets for processing other billing exceptions (80 percent within five to seven days).[43]
  - Targets for long-term estimated meter reading.[44]
  - Goal of answering 75 percent of all emails within 48 hours.[45]
  - The standard for initial customer contact on complaint cases referred by LIPA is 100 percent in 10 days.[46] The standard for resolution of the case is 90 days.[47]
    - Based on these standards a customer may not get a call back to initiate their investigation for 2 weeks and the case may take three months to resolve.
    - National Grid tracks its case backlog and periodically reports this information to LIPA.[48] As of the end of May 2013, due to Sandy, the backlog was running about 2 to 3 months.
  - The call center has an outbound collections contact rate of standard of 68 percent (including messages). This is the only formal standard for outbound dialing. There is an informal target of 100-132 checks collected per part-time agent per month. Assuming approximately 150 calls per day, this amounts to an effectiveness rate of about 4 percent.[49]

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[41] Long Island Customer Assistance Center Appeal Process (DR 102)
[42] Long Island Customer Offices Appeal Process (DR 102)
[43] IR 118, Fact Verification
[44] Customer Meter Services Monthly Operating Report, provided during monthly meeting.
[45] April 2013 Customer Service Level Indicators
[46] IR 16 and 151. In Fact Verification, National Grid indicated: the standard of 100% in 10 day is a goal for response back to LIPA on the customer's complaint, not the initial customer contact. Generally, initial customer contact is made within 24-48 hours for non-urgent matters. If it is considered urgent the customer will be contacted the same day the complaint is made.
[47] According to LIPA, while some complaints (e.g., tariff, billing, collections) can be resolved fairly quickly, others take a longer time for investigation and resolution.
[48] Not part of the formal monthly reports
[49] IR 189

14.3.7 LIPA receives adequate information regarding customer service operations and service levels from National Grid, but has little authority to force change under the MSA.

- National Grid provides LIPA with detailed reports on customer operations performance, as well as on the MSA metrics.
- LIPA and National Grid meet formally on monthly basis to discuss operations, performance and potential service issues. The meetings include the call center, customer meter services, customer financial services and customer arrears.[50]
- LIPA receives daily emails providing call center statistics.[51]

14.3.8 OSA metrics, service levels and reporting requirements following the transition to PSEG-LI had not been defined or developed as of mid-2013. As a result, NorthStar cannot confirm that LIPA will receive adequate information regarding customer service operations and service levels following the transition.

- The OSA between LIPA and PSEG-LI designates performance metrics as either maintenance metrics (current performance is adequate) or improvement metrics (current performance is inadequate). All of the current customer service metrics are designated improvement metrics.
- LIPA and PSEG-LI are currently developing the Tier 1 (OSA performance incentive/ disincentive), Tier 2 (operational) and Tier 3 (employee-level) metrics required under the contract.

14.3.9 LIPA has a formalized process for handling customer complaints and inquiries that have not been resolved by its service provider.

- Section VI of LIPA's Tariff for Electric Service outlines a formal complaint procedure which defines the complaint process, outlines the roles and responsibilities of LIPA's staff, the Authority's Manager, and the President/CEO (in the event of an appeal), and sets forth the rights and obligations of the customer. The tariff is available on LIPA's website and summarized in **Exhibit 14-12**.
- If the customer is dissatisfied with the result of LIPA's complaint resolution process it may undertake an Article 78 Proceeding as defined by the New York Code. Article 78 Proceedings provide customers an avenue to challenge the determinations of administrative agencies, public bodies, or offices. An Article 78 Proceeding is the final option available to a customer after all other options have been exhausted. Article 78 proceedings must be brought to the New York State Supreme Court within four months after the Authority's decision. An Article 78 Proceeding, if determined

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[50] Long Island Customer Offices Appeal Process (DR 102)
[51] DR 108, DR 376

in the favor of the customer, allows for financial restitution and a prohibition against associated behaviors. [52]

Exhibit 14-12
Tariff Section VI.1 Summary of Complaint Procedures

1) LIPA customers are encouraged to first contact the Authority's Manager. The Authority's Manager is obligated to promptly investigate in a fair manner and inform the customer of the outcome. If the customer is not satisfied with resolution of the complaint, the Authority's manager is to inform the customer of the availability of the Authority's complaint handling procedure and provide the Authority's contact information.
2) LIPA staff will accept and investigate all complaints. LIPA staff has the broad authority to request necessary information from both the customer and the Manager, require inspections or tests, and take any other reasonable action to fairly decide the complaint. The customer cannot be terminated for nonpayment during the complaint period plus 20 days and has the right to an appeal to the Authority's President and Chief Executive Officer.
3) If the customer disagrees with the staff's decision, the customer has 15 days to file a written appeal with the Authority's President and Chief Executive Officer. Appeals are limited to mistake in facts, non-consideration of information, and new facts or evidence. A different Authority staff member will be assigned to investigate the complaint. The staff member will make a recommendation and the Authority's President and CEO will make the final decision. The customer will be notified in writing of the decision.

Source LIPA Tariff Chapter VI

- In October 2012, LIPA developed an internal, formal complaint procedure outlining the steps in the process and providing process flow diagrams for each type of complaint: LIPA Initial, LIPA Escalated, Appeal and Executive/External.[53]

  - LIPA Initial Customer Complaint: If National Grid cannot resolve a customer inquiry or concern, they are to forward the customer to LIPA Customer Service. These complaints represent LIPA's first involvement with a customer complaint. Initial complaints may also include those that went directly to LIPA without the customer contacting National Grid. **Exhibit 14-13** (following) provides a flow chart of the process. The process includes the responsibilities of both LIPA Customer Service and National Grid Customer Service and the coordination points are documented.
  - LIPA Escalated Customer Complaints: Escalated complaints represent those complaints where there has been initial contact with LIPA but the customer concerns were not fully resolved or they have reoccurred. The process for escalated complaints centers on the review of information associated with a previous complaint or circumstance. **Exhibit 14-14** provides a flow chart of the process.

[52] http://www.lawny.org/index.php/housing-self-help-141/housing-and-eviction-self-help-142/192-article-78-proceedings-how-to-appeal-an-agency-decision
[53] DR 102

- Appeal Process: When a customer is not satisfied with LIPA's resolution of a complaint, the customer is informed of LIPA's Appeal Process. The process requires a letter appealing the complaint resolution to the President of LIPA. **Exhibit 14-15** provides a flow chart of LIPA's appeal process.
- Executive Complaints/LIPA Complaints: Complaints originating from either a communication to the Governor, a State Officer, the LIPA Board or the President of LIPA are forwarded to LIPA for resolution. The complaints are handled either as a LIPA Initial Complaint or a LIPA Escalated Complaint depending on the history of the complaint. LIPA reports the resolution of complaints to government offices or agencies when they are the source of a complaint.[54]

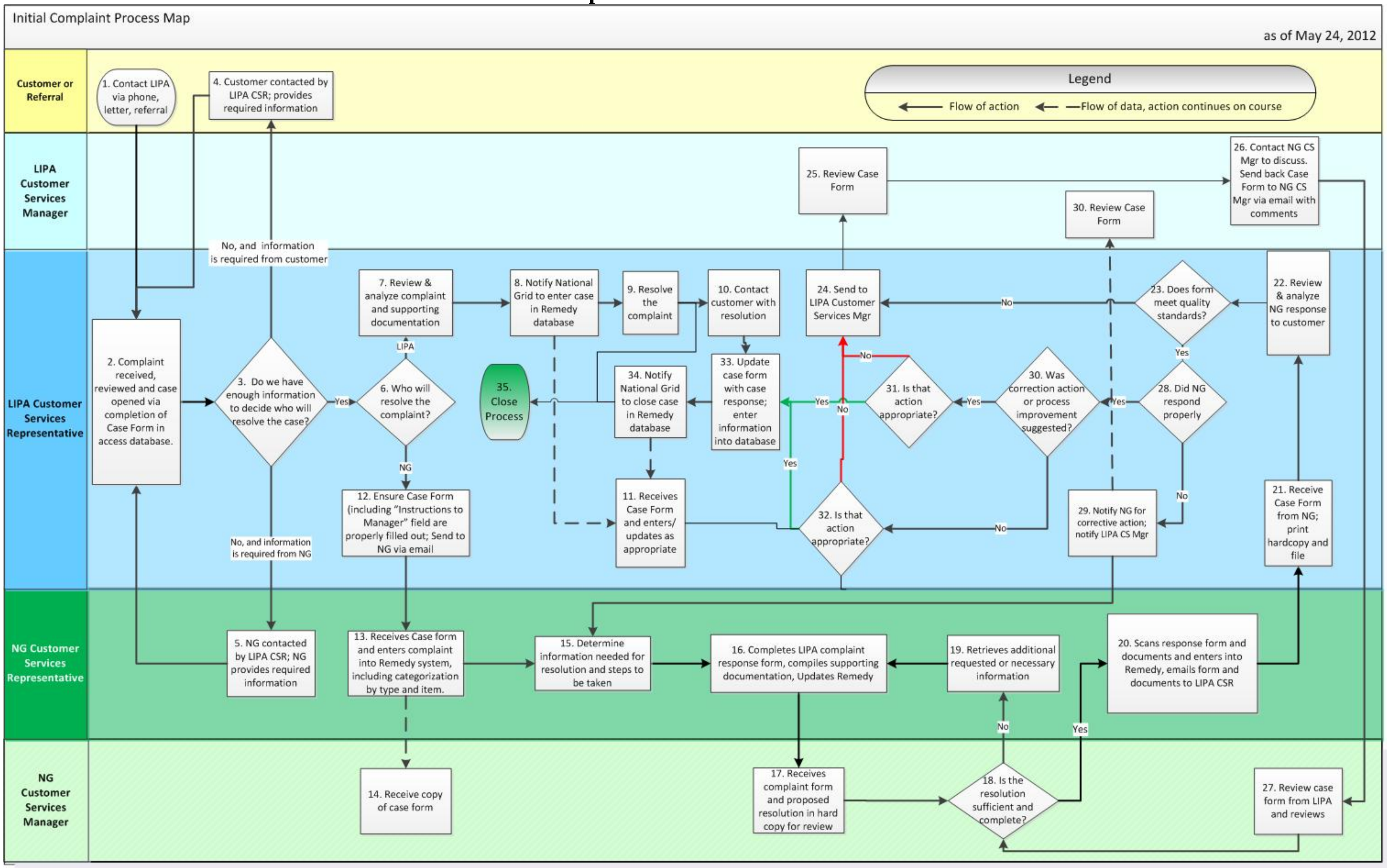
14.3.10 While LIPA has a defined process for reviewing and investigating complaints, resource constraints make independent review of an escalated or appealed complaint challenging.

- LIPA's tariff requires that in the event of an appeal, the Authority's President and CEO will "assign a staff member who has not worked on the complaint before to promptly and fairly review the appeal. The staff member will examine the papers submitted with the appeal and in the complaint file, and advise the President and Chief Executive Officer (or his/her designee.)"[55]

- LIPA has one manager and two CSRs handling initial, escalated and appealed complaints. As result of such a small customer service organization, the potential exists for the same individual determining resolution of the initial complaint to also review the appealed or escalated complaints.[56] LIPA's Tariff Chapter VI.1 – Summary of Complaint Procedures requires that a different individual handle the appealed complaint than who handles the initial complaint. NorthStar reviewed the appealed complaints since 2010 and found LIPA in compliance with the tariff.[57]

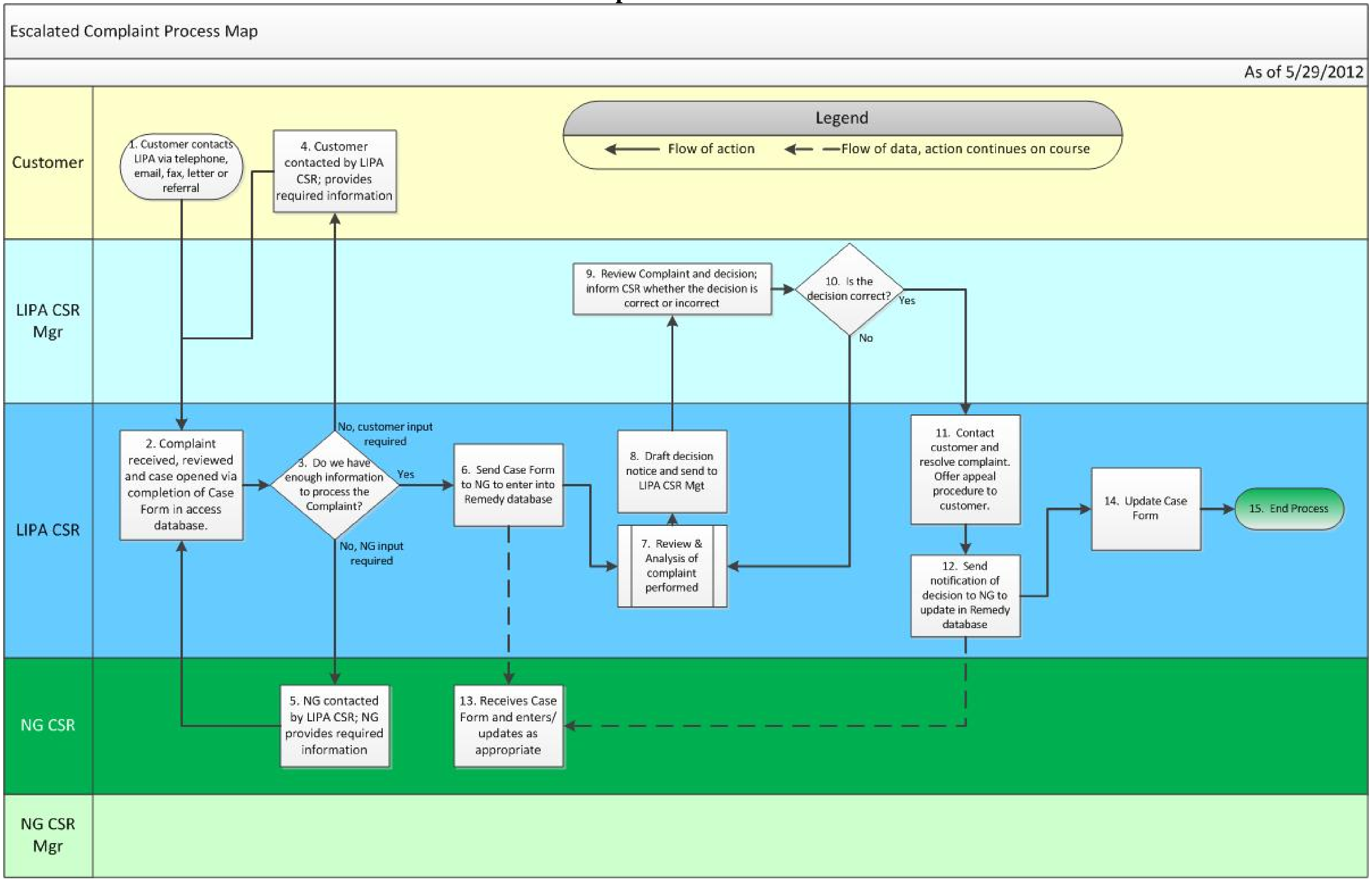
[54] IR 67 Sullivan
[55] Tariff, Section VI.F
[56] In Fact Verification, LIPA asserts this does not happen in practice.
[57] DR 623

Exhibit 14-13
Initial Complaint Process



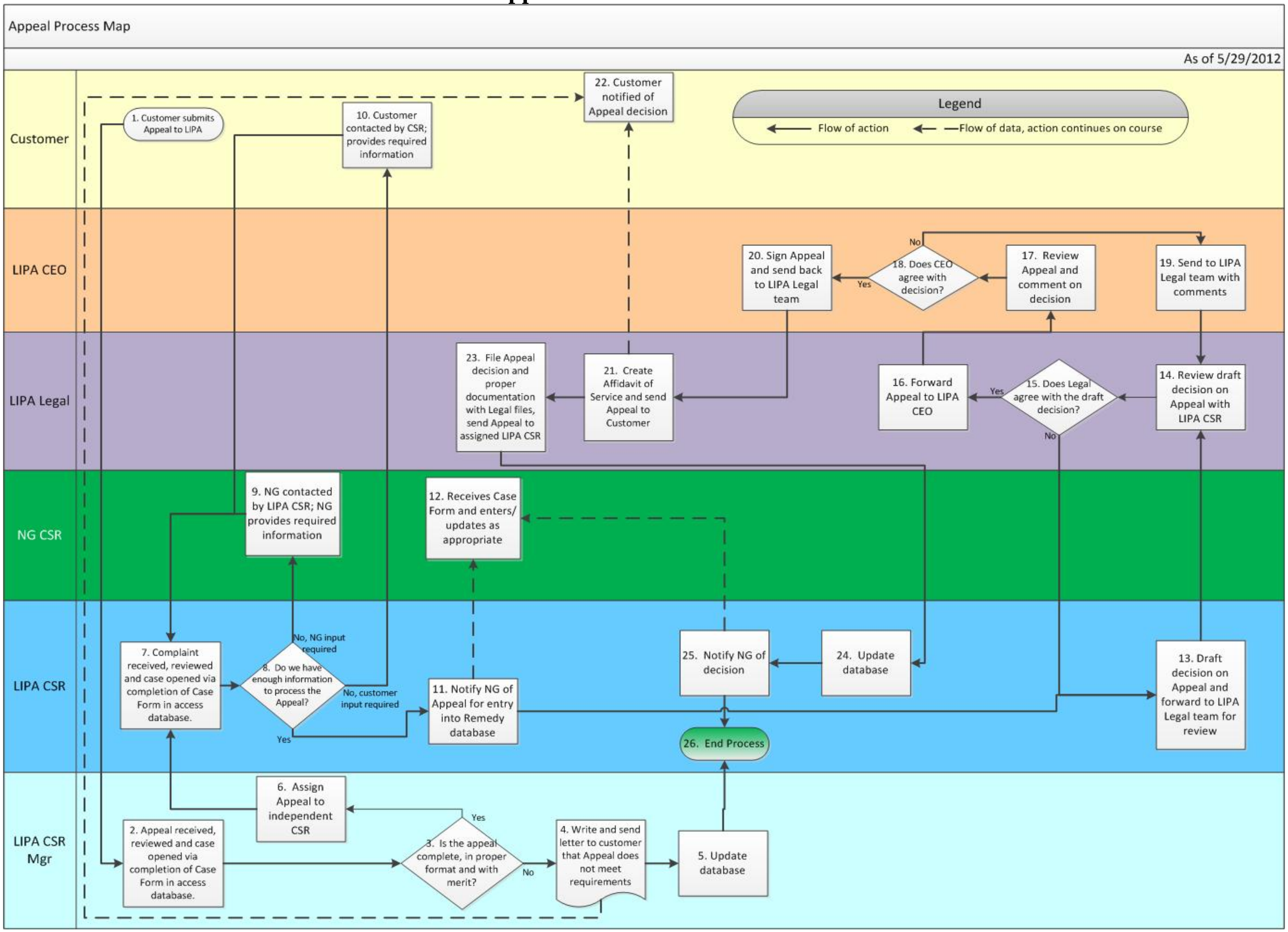
Source: DR 102

Exhibit 14-14
Escalated Complaint Process



Source: DR 102

Exhibit 14-15
Appeal Process



Source: DR 102

14.3.11 LIPA appropriately monitors the level and nature of complaints it receives directly and those forwarded to LIPA by the DCP.

- Customer complaints are transmitted between LIPA and National Grid via the Customer Complaint Form.[58] LIPA is responsible for initiating the form. The form includes the following information that is captured in the complaint database:

  - Case Number
  - Relevant Customer Information
  - Relevant Dates
  - Case Status
  - Complaint Type
  - Details of the Case including description of the problem, customer comments, instructions to National Grid and case notes.

- LIPA uses an MS Access® data base to manage complaints. LIPA logs the date the complaint was opened and the date it closed the complaint. LIPA also maintains records on a monthly basis of the number of open complaints by CSR. NorthStar was provided spreadsheets from the database that show how data is maintained. It did not include an aging report.[59]

- National Grid provides LIPA with monthly reports tracking the numbers of initial and escalated complaints made to LIPA per 100,000 customers. The report also includes a discussion of complaint drivers, trends, and potential process improvement opportunities.[60] LIPA's Customer Service organization confirms National Grid's reported numbers with those maintained in its complaint database.

- LIPA meets with National Grid on a monthly basis to discuss the complaint process.[61] Issues and trends identified as a result of the review of complaint statistics or individual cases may be identified and discussed during the course of this meeting.

- LIPA classifies complaints it receives in five types according to its processes. **Exhibit 14-16** provides a breakdown by type.

[58] DR 624
[59] DR 623
[60] Review of monthly reports (DR 102)
[61] Meeting attendance

Exhibit 14-16
Complaint Status Levels

Complaint Level	2010	2011	2012	1/1 – 6/12/13
Initial Customer Complaint	523	638	686	405
Escalated Customer Complaint	18	72	36	14
Appeal	16	25	9	6
Executive (can be an initial or escalated complaint)	16	6	27	4
LIPA (can be an initial or escalated complaint)	42	91	6	
Blank	180		6	2
Total	795	832	770	431

Source: DR 623, data provided during on-site working session

- LIPA also monitors the nature of customer complaints in the "Complaint Type" field of its complaint database. As shown in **Exhibit 14-17**, the majority of customer complaints are related to billing and collections.

Exhibit 14-17
Customer Complaints by Types

Complaint Type	2007	2008	2009	2010	2011	2012	1/1 – 6/12/13	Total
Billing	131	128	177	191	208	123	104	1,062
Claims	4	3	3	5	9	13	10	47
Collections	79	80	127	245	248	181	76	1,036
Cust Order Fulfill						22	18	40
Customer Service						45	38	83
High Bill					29	48	69	146
Meter Reading						3	8	11
OH/UG Lines						26	30	56
Other	41	39	35	33	35	16	6	205
Payment Processing						1	2	3
Rate Consultant	1			16	12	7		36
Rate/Tariff					1	13	9	23
Rev Prot/Adv Cons						7	5	12
Service	149	142	92	235	221	49		888
Shared Meter	58	45	36	26	32	34	11	242
System Ops						140	28	168
Tree Trim	27	32	6	44	37	42	17	205
Grand Total	**490**	**469**	**476**	**795**	**832**	**770**	**431**	**4,263**

Source: DR 623, data provided during on-site working session

14.3.12 LIPA does not receive any information on or monitor complaints or inquiries resolved exclusively by National Grid.

- National Grid handles large volumes of customer calls that fall into a variety of categories: 1) general inquiries; 2) complaints that are quickly and easily resolved by the contact center; 3) repeat calls to the contact center regarding the same issue; 4) calls which are escalated within National Grid; and, 5) calls/issues that may be ultimately unresolved but for which the customer does not contact LIPA.

- National Grid tracks complaints escalated to the Supervisor level; this information is not reported to LIPA. According to National Grid, LIPA has never requested this information.

14.3.13 While customers billed through the batch process generally receive timely bills, this may not be the case for some manually generated bills or bills with billing exceptions; the continuing impact of Sandy has reduced the timeliness of the resolution of billing exceptions.

- The vast majority of LIPA's accounts are billed through the batch billing process. For batch bills, meters are read on Day 1, Read Verification is performed on Day 2 and bills are mailed on Day 3.[62] National Grid personnel interviewed could not recall any instance where an entire bill batch was held.[63]

- LIPA has an agreement with Pitney Bowes, its bill printer, to deliver bills to the Post Office by 6:00 pm on the same day the data has been provided. In order to meet this deadline, National Grid must provide bill data to Pitney Bowes by 5:30 a.m. During the past 39 months, the target was not met on 24 different instances. This represents an on time metric of 97 percent. A total of 880,000 customer bills were affected over the 39 month period. Sixty-three percent of the delayed bills resulted from National Grid issues, 24 percent were weather or US Postal Service-related, and the remaining 13 percent were Pitney Bowes' errors.[64]

- Only about 18,000 accounts are manually billed. Manually billed accounts are processed based on separate timelines developed for each account type.[65] NorthStar found some irregularities in the sample of manual billing information provided for August 2012. **Exhibit 14-18** summarizes NorthStar's findings.

- **Exhibit 14-19** provides the number of billing exceptions and the average number of days to resolve them in July 2012, and in March 2013 following Sandy. (Further discussion of billing exceptions is provided in Conclusion No 14.3.15). **Exhibit 14-20** provides the age distribution as of March 2013. With the exception of MRP meters, most are resolved within 5 days.

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[62] Day 6 for Green Choice Customers
[63] IR 118
[64] DR 617 calculated as 1-(24 instances/(39 months*20 runs per month))
[65] DR 683

Exhibit 14-18
Special Billing Irregularities – August 2012

Account Type	Number of Accounts	Requirement	Date Completed	NorthStar Analysis
Recharge NY	100	Completed and sent to NYPA by the 10th of the month	9/20/2012	Late
Co-Generation SC-12	16	Completed by the 2nd week of the month	9/19/2012	Late
SC-13 (Special Contracts)	2	Completed by 3rd week of the month	10/1/2012	Late
Brookhaven National Lab	2	Completed by first week of month	9/28/2012	Late
EUGOBOS – Company Books	1,167	Completed by the 20th	9/21/2012	Late
Total	**1,171**			
Total Manually Billed Accounts	**18,757**			
Percent	**6.2**			

Source: DR 683

Exhibit 14-19
Total Billing Exceptions and Average Days to Complete

	July 2012		March 2013	
	Total Items	Average Days to Complete	Total Items	Average Days to Complete
Hi/Lows	4,914	2.26	5,012	3.97
Regular	7,810	2.82	11,288	4.61
Demand	9,172	4.68	13,454	3.06
MRP	3,022	5.68	3,915	49.53

Source: DR 107 and 481

Exhibit 14-20
Billing Exception Distribution of Days to Complete March 2013
(Percent)

Days to Complete	Hi/Low	Regular	Demand	MRP
1 Day	11.4	12.1	16.2	16.1
2 Days	13.9	16.5	29.2	10.3
3-5 Days	58.7	46.4	48.8	12.6
6-10 Days	15.5	18.9	5.5	17.0
11 or more days	0.5	6.2	0.3	44.0
Longest	72 days	164 days	80 days	97 days

Source: DR 486

14.3.14 As a result of LIPA's bi-monthly read process, a significant portion of customer bills are based on estimates rather than actual consumption.

- As shown in **Exhibit 14-21**, about 70 percent of LIPA's customers are billed based on actual reads every other month and estimated reads for the in between month.

Exhibit 14-21
Percent Estimated Reads

	2010	2011	2012
Read bimonthly, billed monthly	787,636	793,831	797,595
Percent estimated	**70.0%**	**71.2%**	**70.8%**
Read bimonthly, billed bimonthly	199,637	193,212	188,244
Read monthly, billed monthly	137,353	127,933	140,191
Total Bills	**1,124,626**	**1,114,976**	**1,126,030**

Source: DR 421

- Computer generated estimates for energy are used whenever possible for the months where there are no actual reads. The computer estimates are based on the previous year's actual consumption or the average of the previous year's two month data of actual and estimate. When a computer estimate cannot be generated, most recent history is utilized to develop an average usage that is applied to the estimated bill. When the customer has a new facility, the estimate is based on pro forma average daily usage.[66]

- As of April 2013, the 12-month rolling average number of residential meters with long-term estimates (LTE) was 7,869 (less than 1 percent of LIPA's meters). The target is 6,900. Of those meters, 43 percent had consecutive estimates for 3-4 months, 25 percent for five to eight months and 33 percent were nine months or greater. The number of commercial LTEs was 6,139 (about 5 percent of meters) relative to a target of 5,137.[67]

- Estimating can build in long-term inaccuracies.

  - Usage is generated on estimates, but is charged at actual monthly rates. LIPA's base rates change seasonally and the power supply charge changes monthly.[68]
  - Estimated bills result in a customer meter not being read for at least two and possibly four consecutive months. In case of basic kWh meters, eventually the actual consumption will be reconciled with estimated consumption, but billed at the current month's rate.
  - Demand meters, however, record the highest demand since the last meter read. There is usually no time stamp to determine when the highest demand actually occurred. A demand is estimated for 3 of the 4 months and can never be verified.

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[66] DR 681
[67] Customer Meter Services Monthly Operating Report, Month End April 2013, provided during monthly meeting
[68] http://www.lipower.org/powersupply/

- Estimated demand is based on the "same time last year" methodology where an estimated demand is the same as the demand seen the previous year.[69]
- LIPA has a procedure to attempt to re-read demand meters within 12 days before a demand estimate is generated.[70]

- If National Grid is unable to read all of the meters in a cycle, those bills are estimated. During the normal course of business, if a meter reader is unable to finish reading the routes before the required deadline, the meter reading books are forced to completion and loaded into the billing system.[71] If readings were not obtained for certain accounts, the billing system estimates where applicable or creates an error memo alerting Account Processing to review those accounts.[72]

- The MSA has metrics associated with meter reading performance. **Exhibit 14-22** provides National Grid's performance, MSA target performance and the penalty thresholds. National Grid's meter reading performance was above the target level for all years except 2011; however, meter reading performance targets are not particularly aggressive.[73]

Exhibit 14-22
Meter Reading Performance Metrics

	Actual Meter Reads (Percent)
Penalty Threshold	< 94.78%
Target	96.13
2007	96.72
2008	96.85
2009	97.01
2010	96.29
2011	95.59
2012	97.54

Source: DR 412

14.3.15 National Grid has a fairly typical system of controls to ensure the accuracy of the bill calculation.

- There are a number of controls built into the meter readers' ITRON devices and the meter reading process:

[69] DR 681
[70] DR 617
[71] DR 617
[72] DR 617
[73] As examples: 2012 NSTAR- 99.3%, MEC – 98.8%, Western MA Electric – 99.6%, Nantucket – 99.8%, 2008 Atlantic City Electric 98.4%

- The ITRON handhelds require a meter reader to re-enter a read if it is outside certain tolerances. Supervisors receive route status summary reports which indicate if a meter reader repeatedly enters rereads.
- The ITRON devices do not contain data on a meter's past consumption and additional controls exist to prevent meter readers from deriving it. This prevents the practice of a meter reader entering reads without actually reading the meter.
- Supervisors conduct walk-alongs and field audits. The field audit goal is 400 audits per month across six supervisors and seven locations.[74]
- There are multiple meter reading uploads to ensure all routes and reads get entered into the CAS system.[75]
- System generated reports identify meters with long-term estimates, bills rendered and corrected, and bills not mailed for two or more cycles.[76]

• National Grid performs bill verification after each billing batch run for a sampling of rates across all rate classes. For simple rate structures, the verification process is conducted using an Access database whereby a sample of bills are recalculated and compared with those produced by the billing system. For more complicated rates (Demand/Time-of-Use, Dusk to Dawn, traffic signals), a manual calculation is performed to validate bill accuracy.[77] A background validation of all bills is performed nightly.[78]

• Billing exceptions are generated to highlight potential meter reading or billing anomalies.

• The billing system recognizes over 400 possible billing exceptions resulting in approximately 25,000 to 30,000 bills being reviewed on a monthly basis.

• Twenty percent of billing exceptions are for potential high bill reads.[79] LIPA uses a tolerance of 300 percent of the previous year's average daily usage. In the summer months, an average daily usage comparison is done for months with similar cooling degree days. When the 300 percent threshold is met, LIPA issues a high billing exception for all bills over $1,500.[80]

• National Grid has defined procedures for the calculation of each classification of manual bill which include separate verification tests to ensure billing accuracy.[81]

• National Grid investigates customer-initiated high bill complaints. **Exhibit 14-23** provides details of the numbers of high bill complaints investigated over the last three years.

[74] IR 117, Customer Meter Services Monthly Operating Report, Month End April 2013, provided during monthly meeting
[75] IR 117
[76] Meter Reading reports (IR 153), IR 117
[77] DR 111
[78] IR 118
[79] DR 111
[80] DR 685
[81] DR683

Exhibit 14-23
Field Investigation of High Bill Complaints

Year	High Bill Complaints	Complaints Sent to Field		Resulting in Meter Test	
		Occurrences	Percent	Occurrences	Percent
1/1 – 5/31/13	8,065	942	12	301	4
2012	10,443	1,381	13	415	4
2011	11,760	1,532	13	405	3
2010	11,864	1,239	10	393	3

Source: DR 686 and DR 687

- Based on the bill verification process conducted each billing cycle, NorthStar found no evidence of systemic inaccuracies in the calculation of bills. As discussed in the next conclusion, NorthStar found anecdotal incidences of billing irregularities due to changes in the billing system, the customer, and the rates.[82]

14.3.16 Historically, National Grid has had problems with assignment of rates and controls over the implementation of rate changes in the billing system. Errors are corrected after the customer is billed and controls instituted after the fact.

- National Grid does not have a sufficient process to ensure customers are on the correct or most advantageous rate.
  - For most customers, rates are set at turn-on. Commercial customers must fill out an application which asks for the type of business and if it is similar to the prior business. Customers are typically assigned the same rate as the prior occupant.[83]
  - New construction goes through the Customer Order Fulfillment (COF) group which assigns the rate.[84]
  - Customers are annually mailed a booklet on rates; however, it is unlikely that most customers review the booklet or their rates.
  - Exceptions are generated for usage levels greater than allowed by tariff, which might identify a rate classification issue.[85]
  - MAEs may review the rate classification for customers they manage.

- Numerous press articles have highlighted errors in rate class assignments in the residential class. LIPA instituted new protocols in 2011 when customers sign up for service to verify rate class.[86]

[82] DR 78
[83] DR 489
[84] IR 118
[85] IR 118
[86] IR 152, http://www.newsday.com/opinion/lipa-refund-right-thing-to-do, http://www.lipaoversight.org/2011/07/27/lipa-national-grid-must-come-clean-with-billing-errors

- In 2011, a number of large commercial accounts were billed on the incorrect service classification. When meters were changed, the service level (transmission, primary, secondary) was incorrectly coded in the field, resulting in the wrong rate code assignment. New controls have been implemented to prevent this from happening in the future. Service classification is now hard-coded in the system and COF or field sign-off is required to change the classification [87]

- In 2011, 1,200 customers received incorrect bills. The total billed amount was correct but the line items were incorrect. LIPA determined there was an error in updating seasonal rates in the bill presentation. New controls are in place to prevent this from happening in the future.[88] In response to this and other issues, in June 2011 LIPA publicly chastised National Grid, "demanding immediate action to improve National Grid's billing procedures and practices as they affect LIPA customers", expressing continued frustration with National Grid's handling of billing issues.[89] LIPA cited the following billing issues:

  - Misprinting of bills for electric heat customers
  - Limited follow through with LIPA approved bill process improvements
  - Ongoing issues necessitating repeated follow-up and recovery
  - Fewer customer service representatives to respond to billing inquiries.

- LIPA has identified billing issues in its 2010 Customer Service Strategic situational analysis, its LIRR Billing Project, and its Commercial Billing Project.[90]

- A June 2011, Nassau County Comptroller Report found that its electric bills included double billing and incorrectly charging sales tax to the County.[91]

14.3.17 Due to delays in the response to its data requests, NorthStar is unable to determine whether LIPA provides its customers with accurate and timely information regarding service times, service request or customer inquiry status, outages and estimated service restoration times. However, there are a number of indications that outage estimating is poor.

- Responses to information requests 426 and 611 had not been provided as of July 5, 2013. DR 426 requested information to ensure compliance with HEFPA requirements. DR 611 requested a list of all customer-requested and inquiries for which National Grid provides estimated response or completion dates, the estimated response times or completion dates provided to the customers (pre- and post-Sandy), performance against those estimates, and samples of a routine reports showing performance/compliance.

- CSRs report frequent changes in outage estimates even during "blue sky" conditions.

[87] IR 152.
[88] DR 616
[89] June 10, 2011 Press Release, www.lipower.org
[90] DR 40 and DR 89
[91] www.nassaucountyny.gov/agencies/Comptroller/NewsRelease/2011/06-06-2011.html

- National Grid tracks the percent of billing investigation appointments kept. For 2012, 96.87 percent of appointments were kept relative to a target of 100 percent. For the period January through April 2013, 99 percent of appointments were kept relative to a target of 98 percent.[92]

- Customer-ordered work performed by the COF group is assigned a completion date, based on customer-need (if defined) or based on system defaults if a date for the job is not specified. Typically an electrician sends in paperwork on a customer's behalf and the default completion dates are assigned based on parameters built into Maximo.

- If a customer calls in and indicates they need the work by a certain date the job is assigned a Customer Need Date (CND).[93] National Grid tracks compliance with its performance relative to target dates.

  - For CND work, compliance ranged from 91 to 98 percent during the twelve-month period May 2012-April 2013, as shown in **Exhibit 14-24**.

Exhibit 14-24
CND Compliance – May 2012 – April 2013

Division	Percent On Time or Early
Queens/Nassau	92.86
Central Nassau	92.86
Western Suffolk	90.91
Eastern Suffolk	97.56

Source: DR 609

  - For the period January 2012-April 2013, Maximo target date design compliance ranged from 71 to 81 percent depending on the job type, and construction compliance 70 to 74 percent.[94] The customer is not necessarily aware of the target dates.

- Customers are provided with estimated times for refunds and re-billing.[95]

- For service calls requiring appointments, customers are provided with a four-hour appointment window.[96]

- National Gird has a backlog of high bill investigations, largely due to Hurricane Sandy. Customers currently are being told they might have to wait 10 to 15 days to

92 Customer Meter Services Monthly Operating Report, Month End April 2013, provided during monthly meeting
93 IR 122
94 DR 609
95 IR 137
96 IR 137

get a call back initiating the investigation.[97] Prior to Sandy, the response time was less than 5 days.[98]

14.3.18 The existing customer information and accounting system is dated. While it is reasonably effective, it is not completely efficient.

- Customer bills are generated using CAS and, more recently, EBO. CAS is a COBOL and Assembler code system installed in 1975. It has been in service for well over 35 years. Typically with older systems, maintaining trained technical support resources becomes challenging.

- According to LIPA, the Siebel system is also dated and requires an upgrade.[99] Similarly, the ITRON system is no longer supported by the manufacturer and the software can no longer be upgraded.

- CAS is complex and many newer technologies and systems have been added to the baseline system to increase functionality.[100] Since its implementation, many components have been "bolted on" including different database technologies and client/server architecture for collections and bill inquiry.[101] **Exhibit 14-25** (following Conclusion No. 14.3.19) provides an overview of key interfaces and system add-ons.

- An "Agent Desktop" Graphic User Interface (GUI) was added which provides a more user-friendly interface and allows the call center CSRs to sign into the system once, rather than having to sign in to CAS as well as the other systems such as the outage management system.[102]

- According to LIPA, CAS maintains a 99.89 percent uptime. Maintenance has been outsourced to IBM Services.[103] Currently PSEG-LI plans to use IBM Services after the transition to provide support until the CAS system is replaced.[104]

14.3.19 The CAS system supports LIPA's business needs; although it has numerous limitations.

- As a mature system, CAS has demonstrated the ability to meet current State laws and regulations.[105] NorthStar's review of CAS evidenced coding implemented to assure compliance with various State requirements

[97] Monthly meeting, IR 152. For the first 2 ½ months after Sandy the high bill group was assisting in the call center. Additionally, Sandy has driven up the volume of high bill complaints (e.g., use of electric heaters to dry out premise, and contractor use of electricity).
[98] IR 152, IR 169
[99] IR 66
[100] DR 409
[101] DR 409
[102] CAS Demo (IR 187)
[103] DR 409, 493 and 497
[104] DR 490
[105] DR 409

- The overall on-line availability of 99.89 percent coupled with 'next day' bill printing and ½ of one percent batch abends (unplanned program abort) demonstrates the ability to meet billing needs.[106]

- When National Grid acquired KeySpan, LIPA performed a comparison of the functionality of CAS versus National Grid's CSS System.[107] 801 CAS requirements were identified and matched to CSS; 5.5 percent of the CAS requirements were not met by National Grid's CSS and 14 percent were partially met. For 5.5 percent, CSS exceeded CAS. Features present in CSS that were not available in CAS included the following.[108]

  - Electronic work queues for workflow management
  - Enhanced, web-based training materials
  - Easier system maintenance for routine tasks such as tax and rate changes
  - Real-time updating and posting for most transactions
  - 13 month graph on customer bills[109]
  - Incoming correspondence image capture
  - Additional capabilities for managing deposits
  - Better receivables management and credit and collections enhancements.[110]

- The system maintains a collection of over 1,000 reports which are all viewable online.[111] With the addition of a data warehouse, clients can do ad-hoc reporting.

- Inefficiencies and limitations exist in a number of areas:

  - More complex rates and customer structures such as cogeneration, ReChargeNY, street lighting, and traffic signals are billed manually due to the modifications required to handle in CAS/EBO.[112]
  - System limitations make tariff changes challenging.[113] Changes to the rate structure or bill format are very difficult in CAS. Recent challenges include on-bill recovery,[114] Smart Grid rates and LIPA's ability to offer a three-part rate to electric vehicle users.[115]
  - During the implementation of the Siebel system, National Grid connected Siebel to the EBO bill generator rather than CAS, necessitating the need for workarounds. The systems use different enterprise architecture which does not facilitate efficient data extraction.[116]

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[106] DR 409
[107] IR 66. CSS is the customer billing system used by National Grid for other operating units.
[108] Some of this functionality was subsequently added to CAS.
[109] During Fact Verification LIPA confirmed that this feature is now available on CAS.
[110] DR 490
[111] DR 409
[112] IR 152
[113] IR 118
[114] Customers are able to take out loans with NYSERDA and pay it off for a period of up to 15 years on their utility bill (DR 107)
[115] IR 66
[116] IR 66

- CAS facilitates the emailing of forms, but cannot directly email any materials. Materials are handled offline by the CSRs who manually enter customer name and address information and then mail the necessary paperwork.[117]
- CAS does not store any scanned images except actual customer bills.
- There are no account alerts (although they have a ticker that can be used if need to send messages to the entire call center).
- CSRs must email or call other departments as needed as the system cannot auto-generate notification.[118]
- The only system generated time estimates are outage restoration estimates (when available).[119]
- CSRs report the system is frequently slow.[120]

- The interfaces that exist between the customer systems and other LIPA/NG/external systems appear to be appropriate technologies. In some cases they are utilizing state of the art Websphere and Nuance Communications solutions.[121]

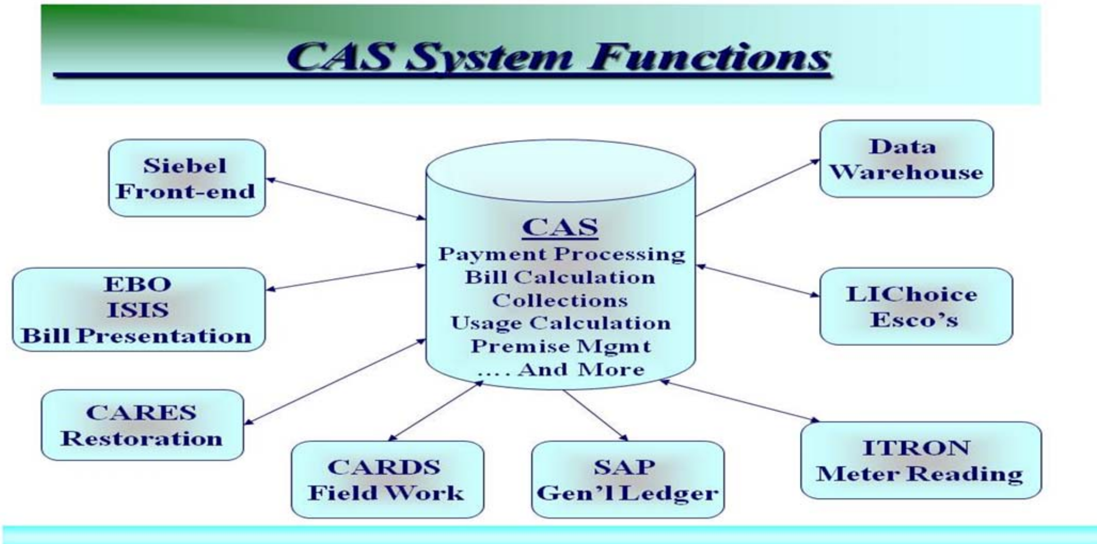
- **Exhibit 14-25** shows the various interfaces between CAS and other systems at LIPA and National Grid. The CAS system interfaces with a number of other components to complete the customer service function including:[122]

  - Siebel Front-end
  - EBO ISIS Bill Presentation
  - CARES Restoration
  - CARDS Field Work
  - SAP General Ledger
  - ITRON Meter Reading
  - LI Choice ESCOs
  - Data Warehouse (Enterprise Data Management system) interface

- There is no direct link between the work management systems and either the dispatch system or CAS. CSRs have read-only access to Maximo, but typically if a customer calls in requesting an update on work status, the CSR will transfer the call to the COF group; most customers contact COF directly for status updates.

[117] CAS Demo (IR 187)
[118] CAS Demo (IR 187)
[119] CAS Demo (IR 187)
[120] IR 61
[121] DR 409 and DR 492
[122] DR 409

Exhibit 14-25
CAS System Interfaces/Functions



Source: DR 409

14.4 Recommendations

14.4.1 Designate or add a senior/executive level position, reporting to the COO, with oversight responsibility for, and experience in, customer operations and communication.

- The transition to PSEG-LI should address this issue on the Service Provider side.

14.4.2 Develop improved service levels and service level standards throughout the customer service organization, both operational and OSA-level.

- LIPA anticipates an improvement in service levels with the shift to PSEG-LI and the ServCo model. The Draft OSA performance metrics incent PSEG-LI to improve customer operations service levels, targeting first quartile performance in a number of key areas. However, these metrics had not been finalized as of May 2013.[123]
- PSEG-LI's proposed organization increases the customer operations staff by about 17 percent from National Grid's estimated current staff level (758 PSEG-LI FTE compared to National Grid's proposed FTE of 650).[124] Increases are proposed for all customer service functions: revenue operations, meter services, customer contact and billing, and customer experience & utility marketing. In light of legislation passed in June 2013, it is unclear whether staffing levels will be increased.
- Improve the call center ASA and other customer service level standards.

[123] OSA
[124] DR 2, Estimates based on National Grid's bid to remain service provider

14.4.3 Develop a Customer Service Strategic Plan (in conjunction with PSEG-LI), including establishment of a formalized approach to customer service performance improvement.

14.4.4 Develop a more analytical approach to the management and evaluation of customer service functions, including collections, that allows for analyses of trends and casual effects, and includes the associated reporting.

- Ensure that the level of customer service operational information does not diminish post-transition.
- Develop an ongoing program of analyzing and understanding customer feedback obtained from the various customer satisfaction surveys as well as customer complaints. PSEG-LI plans to add a planning and dispatch group and a customer satisfaction management group.[125]
- Report information on complaints received by the call center as well as complaints escalated within the call center, at a minimum counts of the numbers of complaints escalated to the various levels of management at the call center to identify potential service problems. Information on the overall number of complaints received by the call center would provide additional information in understanding customer satisfaction levels.
- Develop an increased focus on effectiveness and associated reporting.
- Evaluate relative costs and service-level trade-offs.
- Evaluate the potential for the use of outside service providers to increase effectiveness, reduce costs, and, for the call center, potentially provide additional resources in the event of a major storm event or other disaster.
- Consider moving outbound dialing into the collections organization to facilitate development of a more comprehensive strategy.

14.4.5 Ensure a process is in place, either within LIPA or delegated to another party, to handle external, executive and escalated customer complaints (those that elevate outside of the call center), similar to the process specified in the current LIPA Tariff, and that includes benchmarked specific case resolution service level standards.

Regardless of the branding/name provided to the customers or where official complaint handling is moved, LIPA will likely continue to receive some complains directly from customers. There needs to be a process for the handling of these and other external and escalated complaints.

- Develop and formalize appropriate standards for handling of external, executive and escalated complaints, both for initial contact and resolution.
- Case resolution standards could vary by type or could include percentage based targets (i.e., 90 percent of cases resolved in 5 days with no case exceeding “x” days).
- Develop reporting to monitor compliance with the service level standards.

[125] DR 2

- Continue to ensure that a different CSR handles an escalated complaint than the CSR that has handled the initial complaint. This provides objectivity in resolution of customer issues.
- Develop a complaint aging report that identifies individual complaints that have not been resolved in within the standard days.

14.4.6 Develop and implement a plan to address the backlog of billing exceptions.

14.4.7 Conduct a detailed cost-benefit analysis of a switch to monthly meter reading and discontinuation of the process of bi-monthly estimating, particularly in light of the switch to a monthly power supply charge. In 2011, National Grid estimated the annual incremental cost of switching to monthly meter reading using the current pedestrian route method at about $8 million.

14.4.8 Establish a more formalized rate applications process to improve customer service by evaluating customer rate assignments. Specific activities would be the development of a set of analysis tools to model customer usage across rates, physical inspection of customer facilities, and outreach to customers after analysis is conducted.

Analysis and inspection would determine whether:

- Customer is assigned the most beneficial rate.
- Customer is assigned the correct rate.
- Customers who should be on demand rates are so.
- Residential customer bills are consistent with neighbors or the neighborhood.
- LIPA is receiving the appropriate revenue from the customer base.

14.4.9 Replace CAS within the next five years per the schedule proposed by PSEG-LI.

- PSEG-LI's evaluation of LIPA CIS determined that replacement was not viable during the transition as it requires a 75 person full time project team and duration of 24 to 30 months, but that it is to be replaced in the early-post transition period.[126]
- The PSEG-LI/LIPA transition team is currently performing a technical assessment of the CAS system with the ultimate goal of replacing CAS with a modern CIS within the next 5 years.[127] A number of initial steps have already been taken.
- LIPA provided the results of its CAS Gap Analysis to Lockheed Martin for consideration in the identification of a new CIS. The gap analysis included a wish list and LIPA's future requirements.[128]
- LIPA has mapped the process out as part of the SmartGrid Roadmap from May 2012.[129]
- The transition team, working with National Grid, is in the process of identifying CAS subject matter experts and will start the process of offering ServCo positions to these resources.[130]

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[126] DR 430
[127] DR 493
[128] DR 490
[129] DR 491

15. EXTERNAL COMMUNICATIONS

This Chapter provides the results of NorthStar's evaluation of external communications. Storm and internal communications are addressed in other Chapters.

15.1 Background

At the time of the audit (mid- to late-2012 through mid-2013), LIPA had primary responsibility for the communications and government affairs functions. Under the MSA, National Grid provides support to LIPA in these areas on an as-requested basis. National Grid has primary responsibility for customer service-related communications through its operation of the call center and management of the major account customers. Beginning January 1, 2014, PSEG-LI will assume responsibility for the entire communications and government affairs function under the OSA.

Communications and external affairs responsibilities are distributed throughout the LIPA and National Grid organizations:

- LIPA's Community Development & Governmental Affairs function serves as the liaison to elected officials in LIPA's service territory. District Managers assigned to each of LIPA's four Divisions (Queens/Nassau, Central, Western Suffolk, and Eastern Suffolk) respond to local municipal government official inquiries, addressing constituent complaints and other topics. They also notify the officials on topics of interest or LIPA's activities/programs in their jurisdiction and provide briefings as required.

- LIPA's Media Relations organization handles press inquiries, the writing and coordination of press releases with the Governor' Office, news conferences, and day-to-day media relations. Media Relations also handles LIPA's website and its social media presence.

- LIPA's Marketing and Sales organization, working in close coordination with National Grid's similar organization, handles the marketing and advertising of LIPA's products and services (e.g., balanced billing, MyAccount) and programs (i.e., energy efficiency and renewables) through radio, print and television ads, billboards, mailers, customer bill inserts and the LIPA newsletter (LIPANews). National Grid also manages LIPA's energy efficiency economic development programs.

- LIPA's Regulatory, Rates and Price organization provides information to other internal groups regarding tariff and rate changes to then be communicated to customers or other key stakeholders.

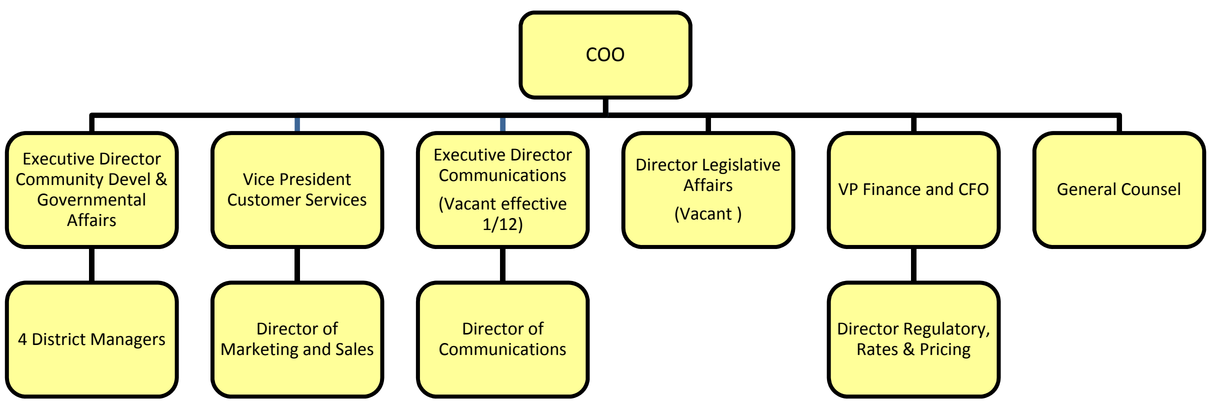
- LIPA's General Counsel handles the various public notification and meeting requirements under SAPA, and receives and processes complaints directed to LIPA as discussed in **Chapter 14 – Customer Service**.

- National Grid's Economic Development and Community Investment organizations, both shared services with National Grid's gas operations, perform two primary functions. Twelve Major Account Executives (MAE) handle the accounts of 585 large LIPA customers in twelve segments (about 25,000 accounts).[1] The Economic Development group works with local communities to attract and retain load and reduce customer operating costs primarily through energy efficiency and other incentive programs.

- National Grid's Contact Center (call center) and Customer Offices handle LIPA customer calls and inquiries. Talking points are developed by National Grid and LIPA working together. LIPA's Marketing and Sales organization interfaces with National Grid regarding programs that may affect customers or the contact center.

Exhibit 15-1 provides LIPA's communications organization as of August 2012.

Exhibit 15-1
LIPA Communications Organization – August 2012



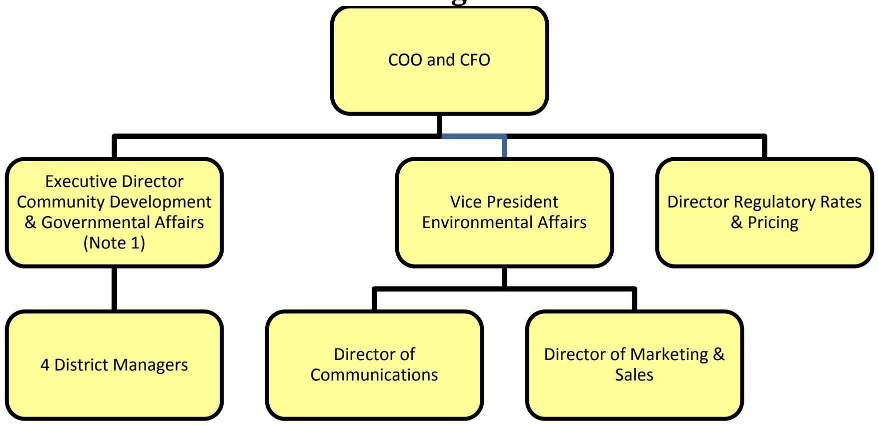
Source: DR 1 August 2012 Organization.

As a result of the departure of key personnel and uncertainty regarding LIPA's future structure, the communications organization has changed significantly over the last six months. **Exhibit 15-2** provides the organization structure as of March 2013.

In April 2013, following the departure of the Executive Director of Community Development & Government Affairs, the four District Managers were moved under the VP of Environmental Affairs.

[1] IR 52

Exhibit 15-2
LIPA Communications Organization – March 2013



Note 1: Position vacated in April 2013.
Source: DR 1 March 2013 Organization

15.2 Evaluative Criteria

- Does LIPA provide customers with timely and accurate information regarding rate changes, major policy issues or other areas affecting the customer?
- Has LIPA taken measures to ensure that its operations are transparent to key stakeholders?
- Does LIPA use an array of methods/technologies to communicate with its customers?

15.3 Findings and Conclusions

15.3.1 In general, LIPA does not have formal communications policies or plans.

- LIPA has no overall corporate strategy or associated communications strategy, nor does it have a formal communications plan.[2] LIPA maintains an annual marketing/ advertising calendar which coordinates the variety of written messages provided to customers.[3] By default this serves as its "plan".

- LIPA does not have a formal policy for what items should receive a press release.[4] LIPA issued about 60 press releases per year from 2010-2012, with an emphasis in 2012 on reliability improvements.

- LIPA does not have a written media policy or strategy at the organizational level. The Employee Handbook governs employee communication with the media,[5] but does not provide guidance or strategy for the organization overall.

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[2] IR 14 and other interviews, DR 40
[3] IR 14 and DR 40
[4] IR 14 and 64
[5] DR 311

- Although LIPA uses social media it does not have a written social media policy or plan.

15.3.2 The communications organization in effect as of April 2013 does not provide for the centralized control or coordination necessary to ensure a consistent, comprehensive communications plan and message. This should be addressed with the transition to PSEG-LI/ServCo.

- As shown in **Exhibits 15-1** and **15-2**, LIPA's communications and government affairs functions were performed by a variety of groups which did not report into the same organizational unit until March 2013. The recent centralization was driven by personnel departures rather than a planned organizational design. Currently most of these functions report to the VP Environmental Affairs.

- Prior to Hurricane Sandy, LIPA had an Executive Director of Communications position reporting to the COO. The position was vacated in January 2012. Although this position provided greater theoretical visibility of the communications function, it did not include the Governmental Affairs functions.

- Under the OSA, PSEG-LI assumes complete responsibility for communications and external affairs. PSEG-LI has indicated the ServCo Customer Operations organization will handle customer-specific communications, while all other communications functions including media relations, government affairs, rate changes and public notices will be handled by the Communications and Public Affairs organization reporting to the ServCo Vice President Business Services as shown in **Exhibit 15-3**.[6]

Exhibit 15-3
Proposed PSEG-LI ServCo Communications Organization

Source: DR 29.

  - Corporate Communications w be responsible for media relations, internal/external communications, storm/crisis communications, branding and marketing implementation, public affairs, and corporate social responsibility.

[6] DR 29, IR 65

- The Marketing Specialist will have responsibility for the oversight and integration of corporate and utility marketing, corporate branding and advertising, customer marketing oversight and management of the creative services contracts.
- Public Affairs will be responsible for stakeholder relationships including: government officials/agencies; business organizations; environmental groups and civic groups and community engagement.

- Recent interviews have confirmed that the LIPA communications and government affairs functions will be eliminated. Four District Manager positions will be added to the ServCo organization.

15.3.3 Although LIPA complies with various public disclosure requirements, questions of transparency continue to plague LIPA.

- Financial and operational information is available to the public on LIPA's website as required by the Public Authorities Reform Act (PARA) of 2009.

  - Section 2800 of the PARA requires that each state and local authority make its mission, current activities, most recent annual financial reports, current year budget and its most recent independent audit report accessible to the public via its website·[7]
  - LIPA bylaws, mission, codes of conduct and ethics, contracts, budgets, financial reports and other information required under Section 2800 are all available on its website at: www.lipower.org/company/profile/transparency.html.

- BOT and committee meetings are open to the public and noticed as required by the Open Meeting Law; however, BOT meeting information could be more readily accessible on LIPA's website.[8]

  - Section 103(a) of the Open Meeting Law requires that every meeting of a public body be open to the general public except that an executive session may be called. Section 104 requires that public notice of the time and place of such meeting scheduled at least one week prior shall be given to the news media and conspicuously posted at least 72 hours prior. Public notice of other meetings shall be given, to the extent practicable, a reasonable time prior to the meeting. When a public body has the ability to do so, notice shall be posted on its website.[9]
  - LIPA's website contains a listing of schedule BOT and committee meetings for the year. Notification is also posted outside LIPA's office at 333 Earle Ovington Blvd. in Uniondale.[10]
  - In compliance with Executive Order No. 3 issued by Governor Eliot L. Spitzer on January 1, 2007 (Promotion of Public Access to Government Decisionmaking),

[7] PARA

[8] DR 40, review of www.lipower.org, reviews of BOT and committee meeting videos and attendance at the May 23, 2013 BOT meeting, and direct observation.

[9] Open Meeting Law and enabling legislation

[10] Direct observation

all meetings subject to the Open Meetings laws are broadcast via the Internet and are available on-demand for a minimum of thirty (30) days.[11]

- Meeting agendas, documents and webcasts can be found on LIPA's website. Motions to be considered and other information to be reviewed by the BOT are posted on LIPA's website at 5:00 pm the night before the session.

- LIPA holds public meetings and workshops regarding significant operational and tariff changes and other events.

  - Proposed and final budgets are available on LIPA's website.[12] LIPA invites the public to observe the Board of Trustees workshops where LIPA Staff explains the proposed budget to the Trustees. The Trustees question, probe and provide guidance and feedback on the development of the budget. LIPA generally offers two public Trustee workshops in each of the two counties served by LIPA, however, in 2012, only one public workshop was held with respect to the 2013 proposed budget due to the compressed timeframe for approval due to Hurricane Sandy.[13] The public is also able to comment via email and at the BOT session approving the budget.
  - Public workshops and hearings were held as part of a five step public process for the development of the 2010 Electric Resource Plan.[14] The five steps include: publishing a draft outline; soliciting public comment; developing a draft plan; holding public hearings; and issuing a final plan. **Exhibit 15-4** provides a timeline of key events.
  - Public information sessions were held on July 21, August 17 and September 15, 2011, regarding LIPA's strategic review and consideration of alternative organizational structures. There were 29 speakers total at these sessions. The public was also able to comment at the October 27, 2011, BOT meeting.[15]

15.3.4 While LIPA has a defined process for obtaining input on and communicating rate changes, information is not always provided to customers in a clear and timely manner.

- The Authority's rate proposals, as well as other changes to LIPA's tariff and regulations, are subject to SAPA requirements including: a proposal memo available on LIPA's website and at its headquarters; public comment hearings held in both Nassau and Suffolk Counties; proposal and comments summarized for the BOT; resolution placed on the Board agenda at an open meeting; and, BOT discussion and vote on the resolution.[16] The public is also able to submit email comments.

- As required by SAPA, LIPA has held public hearings for its recent tariff changes as shown in **Exhibit 15-5**.

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[11] www.lipower.org
[12] www.lipower.org
[13] DR 605
[14] DR 605, www.lipower.org
[15] www.lipower.org press releases, review of transcript, DR 605
[16] DR 604, SAPA

Exhibit 15-4
2010 Electric Resource Plan Timeline

Event	Dates	Comments
Draft Outline	1/31/08	Noticed via Press Release 1/31/08 Available on LIPA's website: http://www.lipower.org/company/powering/energyplan08.html
Soliciting Public Comment	4/29/08 – Mineola 5/7/08 - Farmingville	No transcript or press releases announcing the comment sessions are provided. Response to comments provided in Appendix C of the draft plan.
Draft Plan Released	3/24/09	Noticed via Press Release 3/24/09. Available on LIPA's website: http://www.lipower.org/company/powering/energyplan08.html
Public Hearings	4/2/09 – Smithtown 4/6/09 – Mineola 4/7/09 - Melville	Noticed via Press Release 3/24/09 Hearing transcripts available at: http://www.lipower.org/company/powering/energyplan08.html#Documents
Email Comments	Accepted through 4/30/09	
Technical workshop	6/15/09 LIPA's offices	
Draft distributed to BOT	1/28/10	
Approved by BOT	2/25/10	

Source: www.lipower.org

Exhibit 15-5
Rate/Tariff Changes – Public Comment

Change Effective	Description	Press Release	Public Comment Sessions	Approved by BOT
2013	Change on-peak energy charge under AMI pilot	None	4/30 Hauppauge (Suffolk County) and Uniondale (Nassau County). No comments in Board resolution.	5/23/13
November 2012	Change in FPPCA – monthly calculation	None	10/1 Hauppauge and Uniondale – five people commented. Comments summarized in Board resolution.	10/25/12
March 2012	Change in delivery service rates	11/10/11	11/30 and 12/6 (on budget) 4 sessions covered both counties – nine people commented. Comments summarized in Board resolution. 2/15/12 (tariff changes)	12/15/11 (budget) 3/1/12 (tariff changes)

Source: DR 607, www.lipower.org, events page and press releases, fact verification.

- Rate changes are primarily communicated through bill inserts, bill messages and by the contact center in response to customer questions.[17] Rate increases and other budgetary matters are covered by the media.

- LIPA communications to customers regarding rate changes are not always clear or timely. For example:

  - Customers were notified of the March 2012 change in delivery rates by a press release on LIPA's website regarding the Authority's proposed budget (the rate increase was not mentioned in the title) and messages on March/April bills. Customers were also provided with a new rate booklet; however, the new rate booklet did not specifically highlight the fact that there was a change. The contact center was provided with talking points on January 5, February 22, and March 16, 2012.[18] The rate change was not mentioned in other bill inserts or the LIPANews.[19]
  - The November 2012 change to a monthly Power Supply Charge was not communicated to customers in a timely or comprehensive manner, partly as a result of Superstorm Sandy. In particular, no bill messages or bill inserts communicated the change.[20] The change was implemented effective November 1, 2012; however, talking points were not provided to the call center until January 11, February 22, April 4, April 8 and April 26, 2013.[21] In January 2013, LIPA added a Power Supply Charge FAQ to its website and the FAQ was expanded in April 2013.
  - With the change to a monthly power supply charge, no proactive communication was provided to either customers or the contact center regarding the potential impact of the change on balanced billing customers.[22]
  - Customer communications address bill impacts and not necessarily the change in the rate.

- Communications which do not specify the difference between delivery rates and the power supply charge or combine the effects of both rates can cause customer confusion in subsequent months if the power supply charge increases. For example, in 2013 LIPA announced that the new budget did not result in an increase in rates, but aggregate rates subsequently rose due to an increase in the power supply charge.

15.3.5 LIPA appropriately uses an array of methods and technologies to communicate with its customers.

- On a monthly basis, business and residential customers receive bill inserts and the LIPANews newsletters which address such topics as energy efficiency programs, LIPA's mobile website, power outage texting, balanced billing, direct pay and

[17] DR 607, review of various communications for the 2012 delivery change and FPPCA change.
[18] DR 607
[19] DRs 40, 499 and 607
[20] DRs 40 and 607
[21] DR 607
[22] Talking points were subsequently developed in response to customer calls and media reports

paperless billing, safety, meter reading, Residential Energy Affordability Program (REAP), life support, customer rights and "A Note from LIPA."[23]

- Customers are able to contact LIPA by phone, email, and text (outages only). LIPA does not currently offer customers the ability to "chat" with a customer service representative on the website.[24]

- Information is available on the website and LIPA maintains a social media presence.

  - LIPA's website contains informational videos on such things as storm-readiness, energy efficiency and renewable energy, how to read your meter, schedules of upcoming public events, videos of LIPA Board and committee meetings, and some limited videos of press events.[25]
  - LIPA established a YouTube channel and Twitter presence in September 2009.[26]
  - LIPA has Facebook and Google+ pages, a LinkedIn account, RSS feed, and posts photos on Flickr.[27]

- LIPA sends targeted email blasts to LIPA customers with information on products and services, the budget or other current topics.[28]

- LIPA utilizes media and print adds to promote LIPA's products and services and its energy efficiency, renewable and economic development programs.[29]

- Account Executives provide personalized management for 585 large commercials customers (approximately 25,000 accounts).[30]

15.3.6 Although LIPA disseminates a lot of information to its customers, it does not effectively communicate major issues affecting the customer.

- As shown in **Exhibit 15-6,** the majority of LIPA's customer's believe communications are not effective, and that measure of performance has been declining.

- Most of LIPA's communications center around its energy efficiency programs and to a lesser extent its products and services (i.e., MyAccount, balanced billing, direct pay, paperless billing and its mobile website).[31] This emphasis is reflected in customer responses to the JD Power survey as shown in **Exhibit 15-7**.

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[23] DR 40, 2012 bill inserts and LIPANews
[24] Review of LIPA website
[25] www.lipower.org
[26] www.lipower.org press release and review of LIPA's YouTube Channel and Twitter feed. Generally, LIPA has less than 100 YouTube views and has about 10,500 Twitter followers (as of May 14, 2013)
[27] Online review
[28] Various interviews and review of selected customer emails.
[29] IR 14
[30] IR 52
[31] Review of bill inserts and LIPANews, DR 40

Exhibit 15-6
Distribution of Responses to JD Power Survey Question 109
"Overall, how would you rate the effectiveness of LIPA's communications?"

Rating (1 unacceptable, 5, average, 10 outstanding)	2010	2011	2012
1-5	62%	64%	66%
6-10	38%	36%	34%

Source: www.lipower.org

Exhibit 15-7
JD Power Survey Response - Communications

Q. 99: Thinking about the most recent communication you recall, what was the topic of the message?	2010	2011	2012
Company Image/Information	5%	16%	11%
Company Information/News	4%	26%	25%
Consumer Safety around Electricity	7%	13%	15%
Corporate Citizenship	1%	3%	2%
Customer Service (telephone #s, payment options, etc.)	3%	24%	27%
Deregulation/Customer Choice	NA	2%	2%
Don't Know	7%	6%	15%
Electric System Improvements	0%	10%	9%
Emergency Preparedness	3%	31%	25%
Energy Conservation Tips	33%	48%	40%
Energy Efficiency Rebates/Financing	6%	30%	21%
Environmental Issues	4%	22%	14%
Natural Gas Prices	4%	7%	5%
Other	2%	4%	6%
Power Supply	1%	9%	5%
Price (rate) change (increase/decrease)	8%	28%	25%
Product or Service Offers	6%	17%	23%
Reliability of electric delivery (always on)	2%	11%	7%
Renewable Energy (wind, solar, etc.)	3%	20%	10%
Smart Grid/Smart Meter Technology	1%	6%	5%

Note: In 2011 and 2012, customers were allowed to select more than one category.

Exhibit 15-7 (continued)
JD Power Survey Response - Communications

Q 100: Where did you see/hear this most recent communication?	2010	2011	2012
Bill Insert	25%	44%	53%
Billboard	1%	N/A	N/A
Direct Mail	NA	16%	17%
Don't Know	2%	1%	2%
E-mail	3%	15%	17%
Magazine	1%	5%	3%
Newspaper	18%	38%	16%
Other	2%	3%	1%
Radio	10%	17%	4%
Television	34%	37%	12%
Text Message	0%	N/A	N/A
Utility's Social Media Site	N/A	3%	2%
Utility Website	2%	11%	8%
Web Advertisement	1%	N/A	N/A

Q 102: What was the topic of the most recent news story/stories?	2010	2011	2012
Community or charity event	1%	3%	3%
Deregulation / customer choice	1%	3%	5%
Don't Know	5%	3%	2%
Electric rate or price change	35%	61%	53%
Emergency Preparedness	-	40%	36%
Energy conservation and efficiency	10%	20%	15%
Environmental or pollution issue	4%	14%	8%
Financial Results	3%	15%	13%
Natural Gas Prices	6%	9%	9%
Other	11%	13%	11%
Power generation supply	5%	16%	12%
Power reliability or outages	17%	37%	42%
Transmission lines	2%	7%	6%

Source: DR 436, highlights added to identify the most frequent responses.

- Overall, easily understood explanations regarding the level of rates are limited. No current information explains in layman's terms the impact of, for example, the on-going need for debt to maintain and develop the electric system.

- Bill inserts and information provided on LIPA's website do not provide for an adequate explanation of costs included in the delivery charge, or taxes and other charges.

- Although the bill inserts and LIPANews promote LIPA's energy efficiency products and programs, it is NorthStar's opinion that they provide little in the way of energy savings tips for customers.

- LIPA used to post a "year in review" press release on its website summarizing activities and accomplishments over the course of the year. This practice was discontinued in 2010.

- As discussed in further detail later in this Chapter, transition communications have been delayed and little communication was performed by LIPA.

- LIPA implemented a proactive storm-related governmental communication campaign following Hurricane Irene. No such communication occurred in the period immediately following Sandy.[32]

- As of the end of May 2013, LIPA had just begun to communicate with customers or government officials regarding the upcoming storm season.[33]

15.3.7 As of May 2013, communications regarding the transition to PSEG-LI had been limited, and there was no clear information on when transition communications would begin in earnest.

- LIPA announced the vote on the public/private partnership on October 27, 2011. LIPA's COO and BOT announced the selection of PSEG-LI as its service provider on December 15, 2011. In June 27, 2012, LIPA issued a press release indicating it was on schedule to transition from National Grid to PSEG-LI as the new service provider. No subsequent press releases had been issued as of July 1, 2013.[34]

- An initial email blast was sent to the Major Accounts customers when PSEG-LI was selected as the new service provider, but no additional communications had been sent as of mid-April 2013.[35]

- As of August 27, 2012, LIPA had not developed a formal transition plan or timeline. According to LIPA, the overarching goal is to "communicate with all stakeholders (internal/external) about the transition when there is substantive information (updates, etc.) to deliver."[36]

- In June 2012, PSEG-LI developed a LIPA Transition External Communications and Outreach Plan which identified key stakeholders, key messages, communication vehicle and content; however, this plan is not widely recognized and had not been

[32] IRs 25, 192, 193, 194, and 195
[33] IRs 166, 168, 195 and review of communication materials
[34] Press releases, www.lipower.org
[35] IR 52
[36] DR 39 and various interviews including IR 14

implemented as of June 2013.[37] A similar communications plan for internal stakeholders was also developed. Detailed timelines were not included.[38]

- PSEG-LI and LIPA held initial meetings with public officials during 2012. The presentation provided an introduction to PSEG-LI and an overview of the new business model.[39] All subsequent communications were handled by PSEG-LI, and LIPA was not involved. In 2013, PSEG-LI met with Suffolk County executives and elected officials from Nassau County and the East End to address PSEG-LI's storm response process.[40]

- PSEG-LI and LIPA established a dedicated website, www.ourlipafuture.info which serves as the primary information source for most stakeholders. It provides relatively limited information including an overview of the new business model, transition updates in April/May 2012, messages from PSEG-LI in February and April 2013, and extracts from PSEG-LI's Outlook newsletters.[41] Subsequent updates have been limited.[42]

- The first town hall presentation to National Grid employees providing information about the PSEG-LI ServCo structure and benefits occurred on April 10, 2013.[43] As of mid-June 2013, many employees still did not know if they would transfer to the new ServCo organization.[44] Uncertainty regarding ManageCo positions was even greater.

- Interviewees confirmed that little if any public communication regarding the transition had occurred as of mid-2013.[45]

15.3.8 The delay in conducting a branding study contributed to delays in transition communications and a lost opportunity to better understand customer issues and needs.

- On June 18, 2012, LIPA issued an RFP for Branding Study Services. One of the objectives of the study was to "evaluate and better understand customer perception of and satisfaction with LIPA as it prepares to transition to a new business model and service provider."[46] As a result of approval delays, the contract was not signed until late April 2013.[47]

[37] In fact verification, LIPA stated that implementation had been delayed due to the uncertainties in future structure and roles.
[38] DR 314, IR 65 and other interviews
[39] DR 39
[40] DR 519
[41] www.ourlipafurture.info
[42] Review of www.lipower.org, May 13, 2013 and July 1, 2013.
[43] Various interviews
[44] Various interviews.
[45] IR 14 and other interviews
[46] DR 313
[47] IR 65

- The first of three research phases in the initial scope was intended to explore customer attitudes towards LIPA, possible improvements and customer familiarity with PSEG-LI. With the delays in project initiation, this phase was eliminated in the current schedule.[48]

- Until the name and logo of the new entity have been finalized, phone numbers that included the LIPA name in them cannot be changed, nor can efforts to finalize communication materials or rebrand trucks and uniforms, among other things progress.

15.3.9 PSEG-LI's initial due diligence did not include the communications functions, as communications were to be LIPA's responsibility under the December 2011 OSA. As a result, deficiencies and improvement plans have not been specifically identified.

- PSEG-LI initial due diligence recommendations did not include the communications function.[49]

- In February 2013, PSEG-LI developed a Corporate Communication and Public Affairs/Change Management Plan and schedule which provided broad timelines; however, change management activities were largely undefined.[50]

- In May 2013, PSEG-LI developed draft high level, post-transition internal and external communications plan, including a draft plan for major storm events. Tactical plans did not exist as of May 7, 2013.[51]

- According to PSEG-LI, it will be modifying the internal communications plans in the last four months of 2013 to reflect messaging that addresses such items as culture changes and customer communications.[52]

15.4 Recommendations

15.4.1 Immediately develop and implement a communications strategy and message to set customer expectations for the upcoming storm season. Communications should address outages, outage management systems, and storm response/restoration processes and the roles of LIPA, National Grid, and PSEG-LI for this season.

15.4.2 Immediately develop a plan for addressing the culture changes and re-education necessary to ensure the existing National Grid work force fosters and promotes the same values as espoused by PSEG.

[48] DR 313
[49] Review of FRR and IR 65
[50] DR 314
[51] DR 317
[52] DR 517

15.4.3 In conjunction with PSEG-LI, immediately begin to implement the Transition Communications Plan, to inform customers and stakeholders of expected changes and to manage expectations regarding the speed of change and how change will be enacted given the same workforce and existing processes.

15.4.4 Develop a comprehensive, coordinated communications, government and public affairs strategy and associated policies/procedures. These should include the following:

- The need to more effectively communicate with all LIPA customer groups and key stakeholders, effectively using all communication vehicles and all organizational units.
- The need to proactively communicate positive accomplishments as well as respond to issues.
- The need to communicate rate and tariff changes in a timely and customer-centric manner. (See Recommendation 15.4.8 for additional details)
- Guidelines to be communicated to employees governing the interaction of all employees with customers or the media.
- Press release guidelines.
- Social media policy.

15.4.5 Communicate issues of significance to customers regularly and in a timely manner.

- As discussed in Chapter 14 - Customer Service, develop a more formalized approach to understanding the needs of customer, their issues/concerns, and communication/ messaging requirements, and align communications accordingly.
- Expand the range of information included in the bill inserts to better communicate issues of interest to customers.
- Develop communications materials and an associated communications strategy to educate customers and stakeholders on Shoreham, the current level of debt, how the payment and issuance of new debt affects outstanding debt, and any proposed changes to restructure or reduce the cost of debt.
- Consider reinstating the "year in review".

15.4.6 Consolidate the communications and government affairs functions.

15.4.7 Consider adding a communications metric(s) in a future revision of the OSA or its metrics.

15.4.8 Improve communication of rate and tariff changes, in conjunction with PSEG-LI's communication and customer service functions, and consideration of the following.

- Include discussion of rate changes in the appropriate monthly LIPANews and/or in bill inserts, including an explanation as to the reason for the rate increase.
- Publish a press release for all rate and tariff changes, which clearly indicate rates are changing.

- Provide information to customers and the call center that provides the amount of the rate change (i.e., $/day or cents per kWh depending on the rate) in addition to the bill impact.

- Clarify communications regarding bill or rate impacts given fluctuating power supply charges.
- Better anticipate the potential impact of rate changes on customers particularly those on assistance programs or balanced billing and developed associated communication.
- Ensure talking points are provided to the contact center in advance of rate change.

15.4.9 Improve the discussion of the bill on the LIPA website and in bill inserts, in conjunction with PSEG-LI's communication and customer service functions.

- Develop an annual "understanding your bill" bill insert.
- Develop a more detailed explanation of the elements of the customer bill for inclusion on the website and the bill insert. Improvements should be made in the following areas: components of the "Delivery & System Charges", costs included in the "Other Charges" including PILOTS, costs which are a "pass through" such as the Power Supply Charge or are typical of municipal utilities.

15.4.10 Improve the information, links and visibility of BOT meetings, minutes and related documents and resources on LIPA's website.

- Include an archive of prior motions and other Board materials and clear links tying information to the specific Board meeting.
- Include a link to Board meeting notices on the Board of Trustee page of the website (http://www.lipower.org/company/profile/trustees.html). "I am interested in… Upcoming Board meetings." Currently meeting notices are only included in the events calendar under the Press and Events Page.

16. STORM COMMUNICATIONS AND RESPONSE

This Chapter addresses various storm-related evaluative criteria included throughout the audit work plan. Results have been consolidated here for ease of review. The information presented below is not intended to be a comprehensive storm response review[1] as LIPA and National Grid's[2] preparation and response to Hurricane Irene and Hurricane Sandy have been the subject of numerous prior reviews including a DPS audit of the response to Irene, the Moreland Commission investigation and the Authority's own After Action Reviews of both storms.

16.1 Background

NorthStar reviewed LIPA's September 2012 Emergency Restoration Implementation Procedures (ERIPs) developed following Hurricane Irene,[3] and the Irene and Sandy After Action Reviews prepared by LIPA and National Grid. As of May 2013, revised, post-Sandy ERIPs had not been completed and were not anticipated until July 2013.

To create a context for the findings and conclusions, this background discussion provides general information on LIPA and National Grid's storm response organizational structure, communications processes, restoration time estimates, call center operations, and lessons learned from Hurricane Irene.

Prior to 2003, LIPA had no storm response or business continuity plans.[4] In 2003, LIPA developed a Storm and Emergency Response Policy (SERP) which assigned responsibilities for LIPA personnel in the event of a storm. It organized LIPA into five teams: Headquarters (answering calls, handle reception) and four groups working inside the National Grid organization to complement the National Grid response operations. The SERP was separate and distinct from National Grid's ERIPs. Based on lessons learned from Hurricane Irene the SERP is being eliminated and LIPA's responsibilities addressed as part of the ERIPs.

Prior to and during the first part of Hurricane Sandy, which made landfall on October 29, 2012, storm response was handled under a dual incident command structure with National Grid responsible for restoration operations and LIPA responsible for communications.[5] In the midst of the response to Sandy and the November 7 Nor'easter, LIPA transitioned storm communications responsibilities to National Grid.[6] National Grid is now the public voice and face of LIPA during major storms and is currently responsible for the communications strategy, planning, implementation and outreach during such events, with LIPA personnel providing support.[7] Following the January 1, 2014 transition, PSEG-LI will assume

[1] A comprehensive storm review was out of the scope of this management audit.
[2] National Grid refers to National Grid's operations on Long Island that are dedicated to the LIPA operations.
[3] While National Grid maintains these ERIPs they are owned by LIPA and will be referred to as such.
[4] IR 24
[5] IR 9 and IR 10
[6] National Grid handled communications during Winter Storm Nemo (February 2013)
[7] DR 275

complete responsibility for communications, community relations and government affairs under the OSA.

Emergency Restoration Organization

To cope with major storms, it may be necessary for National Grid to mobilize the "Emergency Restoration Organization". Under this scenario, restoration responsibility is divided into Operations, Communications and Media Information groups with the following responsibilities.[8]

- The Operations group is responsible for restoring electric service during emergencies. This includes the mobilization and direction of the resources which survey the damage and make the repairs to the transmission and distribution systems. Foreign utility crews[9] and contractor crews are utilized via the Edison Electric Institute's Mutual Assistance Agreement to augment National Grid repair forces under the Emergency Restoration Procedure. The Operations group maintains liaison with the PSC during emergencies.

- The Communications group is responsible for taking customer calls and communicating with special customers, municipal agencies and government officials. This is done through the Customer Care Centers (call center), the District Offices, and through the Communications Coordination Center (CCC) located in Room 210 in Hicksville.

- The Media Information group is responsible for coordinating communications about the emergency with National Grid employees. Regular communications, which include news briefings and releases, are conducted. Special meetings between National Grid field and office forces and the media are coordinated by this group.

In the event of a major storm, National Grid may decide to shift some or all of its substations into "substation dispatch authority" (SDA), or localized operation control, which places those substations under the control of a Substation Area Coordinator (SAC). Local Control establishes compact geographic areas as reporting locations for foreign and National Grid crews and for assigning work. While local control typically speeds restoration, it has historically proven challenging for National Grid and LIPA in terms of availability of information regarding restoration status.

Estimated Time of Restoration (ETR)

During a major storm, restoration time estimates are to be made at least daily at the system and division level.[10] Initial predictions are based on historical data compiled from past storms, e.g., "a typical storm of this magnitude may result in customers being out for x

[8] Current Electric Operations Emergency Restoration Organization Overview Manual (DR 263). National Grid maintains separate Logistics Organization procedures.
[9] Foreign refers to crews coming from outside the Long Island area under mutual aid agreements.
[10] ERIP 1.1.8 (DR 263)

to y days". After the initial damage assessments are completed, the estimates are expected to increase in specificity, ultimately resulting in customer-specific ETRs.

LIPA's storm damage and restoration time estimates are developed using a computer model which calculates the estimated number of customers out of service, the primary and secondary damage locations, and the number of restoration days for primary and secondary jobs. Electric Dispatchers utilize the Computer Assisted Restoration of Electric Service (CARES) system to diagnose electric distribution system problems, create job assignments for field personnel and, during blue sky and minor events, develop restoration estimates for customers out of service. CARES is also used by the call center and other personnel to respond to customer, emergency responder, municipality and other inquiries. CSRs are kept apprised of ETRs through CARES and the CAS for customers whose substations are not under local control. For customers whose substations are under local control, CSRs are provided only with general messaging that does not provide ETRs.

There are three primary types of ETRs which vary in accuracy and specificity:[11]

- **Polygon Estimate** - a computer generated ETR based on average restoration times for specific types of customer outages (singles, line fuses, lockouts, etc.). Polygoning is the process of looking for a pattern of customer outages and grouping the customers with the same assumed cause of outage. The computer calculation used to generate polygon estimates includes dispatch lag time and average repair time. Polygon estimates may be turned off when lag time between outage analysis and job dispatch becomes unpredictable.[12]

- **Dispatch Estimate** - a computer generated ETR based on average restoration times for specific types of customer outages (singles, line fuses, lockouts, etc.). The computer calculation used to generate dispatch estimates is based on only the average repair times and excludes any dispatch lag time. Dispatch estimates are manually turned off when a storm causes extreme damage and normal average repair times are no longer suitable.[13]

- **Field Generated Estimate –** a field crew generated ETR based on an assessment of actual damage conditions causing an outage. Field generated restoration estimates are provided by crews via radio to the Operation Dispatch Centers and then input in the CARES system giving customers the most accurate restoration estimates. Updates to field generated restoration times are made if the current estimate is going to exceed the current estimate in the system.

A number of deficiencies in the ETR process were identified as a result of Hurricane Irene.[14] Specifically, for restoration jobs managed by the Division control centers, there was limited ability to determine customer-specific estimated restoration times until damage

[11] ERIP 2.3.1
[12] ERIP 2.3.1
[13] ERIP 2.3.1
[14] Case 12-E-0283 In the Matter of the Review of Long Island Power Authority's Preparedness and Response to Hurricane Irene, June 2012 (DPS Audit)

surveys were completed and hand polygoning was able to link the repair work locations with customers without electric service. The work assignments were entered into the CARES system, crews were dispatched, and completed work was entered into the system. In many instances, this process was not completed until the fourth or fifth day after significant repair work had begun.[15]

Additionally, local control substations could not provide sufficiently detailed information such that ETRs could be provided to customers. The substations, which were in local control, assigned work by damage locations which could not be tied with individual customer outages. Even when a substation was in a position to estimate the time of completion for the work location, due to the inability to develop polygon estimates at the substations, there was no way for the substation to tie this information to actual customers without electric service. Further preventing the Division control centers and the CSRs from having information on the status of jobs being managed by the substations in local control, the CARES substation module did not communicate with the primary CARES system. Until restoration management was returned to each of the four Division control centers (when repair work significantly decreased), obtaining estimated restoration times for most customers served by the substations under local control was not possible. Thirty-six of the distribution substations in the LIPA system, or 25 percent of the system, were under local control and unable to provide ETRs until day seven or eight of the Irene restoration.[16]

Communications Procedures

During a major storm event, LIPA activates the CCC in Hicksville. All information to be transmitted to the CCC and the call center must be approved by the Chief Coordinator and the President of National Grid's Long Island operations prior to transmittal.[17] Individuals designated as Emergency Restoration Communicators collect the information and transmit it to the CCC at 0600 and 1800 each day. This information is then used by the CCC to develop communications messages to be distributed to LIPA and National Grid employees responsible for the various communications channels and ultimately to customers and other key stakeholders. Interruption status reports are also provided to the PSC. **Exhibit 16-1** provides an overview of the information to be provided.

Twice daily restoration status meetings with operational and communications personnel are to be held at 0700 and 1900 to discuss the damage assessment and priorities, the numbers of customers out of service, crew availability, logistics, coordination with municipalities, restoration times, the customer communications strategy and to provide informational updates.[18] The substations are required to provide a series of reports to System Headquarters through Division Headquarters. All reports are to be printed and approved by the Chief Coordinator prior to the 0700 and 1900 daily progress meetings. These reports provide:

- Distribution circuit outage data.

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[15] DPS Audit
[16] DPS Audit
[17] ERIP 1.1.9, Section 3.1. During Irene these were two separate people. Revised ERIPS had not been developed as of May 2013 so NorthStar cannot confirm that this is one individual post-Sandy.
[18] ERIP 1.1.4 (DR 236)

Exhibit 16-1
Information Availability Schedule

Day	Information
Day 1	Operating highlights Number of customers out of service based on generation
Day 2-4	Substations out or lockouts Substations restored Numbers remaining out of service Numbers of crews (HV, LV, tree trimming) – National Grid, foreign and contractor crews Hardest hit geographic areas Global restoration predictions
Day 4-6	Damage statistics Final foreign and contractor crew counts Crew manpower by substation Area restoration predications (system, maybe division)
After Day 6	Area restoration predications (console, maybe substation)

Source: ERIP 1.1.9 Attachment 1

- A listing of substations under local control.
- The number of jobs pending in the four divisions and estimates of the customers affected by these jobs.
- The number of jobs of all priorities that have been completed in the four divisions since the beginning of the storm and an estimate of the number of customers restored.
- The number of personnel involved in the restoration effort in each of the four Division Operations Centers.
- The personnel assigned to substations for restoration in the four divisions.
- The number of crew personnel involved in the restoration effort in each of the four divisions, including personnel from other utilities, contractors and tree contractors.

Both prior to and after the status meetings, a communications coordination call is held to discuss and strategize communications activities. Discussions center on the key messages to be delivered and the various communications mediums to be utilized. **Exhibit 16-2** provides the communications messaging timeline.

Hurricane Irene Lessons Learned

The June 2012 DPS audit of LIPA's response to Hurricane Irene[19] found significant deficiencies in LIPA's communication with customers and stakeholders:

> "Of the recommendations in the report, the most significant relate to LIPA's communication with customers and public officials. Some customers and public officials experienced difficulties in their efforts to reach LIPA by telephone during the storm and the restoration effort. In addition, the content

[19] Case 12-E-0283 In the Matter of the Review of Long Island Power Authority's Preparedness and Response to Hurricane Irene, June 2012.

of LIPA's messages to customers did not provide timely and accurate estimated restoration times (ETRs). This was an area of great concern to customers and local officials."[20]

Exhibit 16-2
Messaging Timeline

Time	Activities/Messages
0700-0800	Strategy Session – Operations (0700-0730) Strategy Session – Customer and Communications (0730-0800)
0800-0900	Storm Call
0900-1000	Communications Checkpoint CARES Messaging
1000-1100	Muni Call e-Blast, Crew Info, IVR Update, CSR Taking Points, Web Banner Update, Employee Communications, Storm Center Alert Update
1100-1200	Major Account Communications Press Conference
1200-1300	
1300-1400	
1400-1500	Strategy Session – Operations (1400-1430) Strategy Session – Customer and Communications (1430-1500) IVR Update, Web Banner Update, Storm Center Alert Update
1500-1600	Storm Call
1600-1700	Communications Checkpoint CARES Messaging
1700-1800	Muni Call Press Release Major Account Communications
1800-1900	IVR Update, CSR Taking Points, Web Banner Update, e-Blast, Storm Center Alert Update
1900-2000	
2000-2100	Strategy Session Customer and Operations (to strategize overnight messaging)
2100-2200	
2200-2300	Media Talking Points (for use following morning-storm call), Field Talking Points (for use following morning with safety briefing) IVR Update, CSR Taking Points, Web Banner Update, Storm Center Alert Update
2300-0600	
0600-0700	IVR Update, Web Banner Update, Storm Center Alert Update

Source: ERIP 2.3.1 (DR 263)

[20] DPS Audit

LIPA's Irene After Action Report also identified a number of opportunities for improvement. Quicker and more efficient restoration came at the sacrifice of somewhat less robust customer communications.[21] Specifically:

- Pre-storm messages were effective, but fell short in fully setting customer expectations regarding the expected duration of restoration activities.

- LIPA and National Grid were unable to provide customers with accurate restoration times.

- Three issues affected the processing of customer calls and contacts. Some customers received a "fast busy" signal when calling due to limitations in Verizon's capacity to route calls to the call center through their network. A second issue occurred when calls to the 800 numbers were routed off-island. The third was with capacity constraints on processing web outage reports. Capacity issues were also experienced with certain cell phone providers when widespread use of cell phones became the "preferred" method among customers to report outages, at times stressing or overloading the cell system capacity.

- LIPA's Government Relations organization participated in informational calls with municipalities that were hosted by the County Offices of Emergency Management (OEMs). While these calls were helpful to local officials, the sporadic schedule of the calls was not adequate for maintaining communications to many Villages and Towns. Additionally, many municipal officials stated that they do not regularly coordinate their activities through the County OEMs.

- Certain governmental officials provided the private phone number to the CCC to their constituents, compromising the integrity of the municipal number. This phone number was established for the sole use of elected officials and not intended for use by the public. The CCC had neither the appropriate resources nor staffing to support the resulting high volume of customer inquiries.

Sandy Communications

LIPA and National Grid used a variety of methods to communicate with customers in advance of and during Sandy: LIPA's computer and mobile web site/storm mobile web site and the outage map; texting; press conferences; press releases (sent to media outlets, emailed to customers, posted on social sites, and posted on LIPA's web site); email blasts; a variety of social media sites; Public Service Announcements (PSA); print ads and radio spots; and, the call center.[22]

In preparation for Sandy, a number of activities were undertaken to prepare customers for the upcoming storm.[23] LIPA and National Grid:

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[21] DR 124
[22] DR 274 and review of storm communications
[23] DR 257

- Sent e-mail blasts and conducted individual follow-up calls to 546 major account customers, which identified specific actions to take for an event of this magnitude (e.g., test generator backup, ensure adequate fuel supply).

- Contacted hospitals, LIRR, and other critical major account customers to ensure coordination of emergency plans.

- Sent two e-mail blasts to 300,000 customers for whom it had email addresses, providing information on potential hurricane damage.

- Made over 14,000 personal calls to contact 6,005 customers with critical care equipment advising them to be prepared to make alternate arrangements in the event they were without power as a result of the storm.

- Faxed letter to governmental agencies and elected officials.

- Contacted County Executives, Town Supervisors, Mayors and others.

- Updated the website and social media to provide storm tracking, safety and preparedness information, as well as to provide customers with contact information. On Friday, October 26, www.lipower.org was redirected to land on the Storm Center main page.

- Updated the call center Interactive Voice Response (IVR) system updated with Hurricane preparedness and safety information.

- Ran emergency preparedness advertisements and PSAs.

- Conducted 22 press interviews and issued press releases.

- Initiated municipal calls to provide information and updates to elected officials.

During the storm, various functional groups were involved in the communications process. These included Employee Communications and Brand, Operations, Customer Relations, Media Relations, Major Accounts, and Government Relations. Activities included:[24]

- Twice daily, 30 minute municipal calls (39 calls total, beginning October 26).

- The four District Managers established regular points of contact within their assigned territories.

- Beginning on Tuesday, October 30, daily manual call attempts were made to Life Support Apparatus (LSA) customers to conduct a "welfare check" and remind them to continue to take steps to prepare for a multi-day outage. Contact information for those LSA customers that could not be reached was forwarded to the County

[24] DR 257

Emergency Operations Centers (EOCs) for physical site visit or welfare verification through a county department.

- On Monday, October 29, Major Account representatives joined other staff at the CCC to begin information gathering and communication coordination. Throughout the day, Major Accounts reached out to its customers to keep them informed of the status of the LIPA system and to be made aware of any significant customer outages. Special priority was given to critical care facilities (i.e., hospitals, nursing homes, sewage treatment plants, water pumping stations, colleges/universities, public, private K-12 schools, fire houses, multi-family and villages). Additionally, Major Accounts closely monitored oil terminals and made sure that back-up generation was available so that the terminals were energized on a 24-hour basis.

- Nine press releases were sent out during the storm and subsequent restoration.[25]

Call Center

As of October 25, all employees were advised that vacations were cancelled and they were placed on mandatory 16-hour shifts. Additionally, a supplemental workforce of National Grid Long Island employees from outside the customer organization was called in to assist. On October 25, National Grid distributed pre-storm messaging and talking points to the CSRs in the call center and the customer offices. During the storm, talking points were provided at least twice daily. Staffing at the call center was enhanced to a peak of 350 employees on the phones for the 24/7 duration of the storm. Increased staffing began at 1800 on Sunday, October 28. By 1200 on Monday, October 29, the Call Center had tripled regular staffing. The day prior to the event all supplemental team members were brought in for a refresher course and an on-boarding session in the call center. Customer walk-in offices were closed from Monday, October 29 through Monday, November 19 to free up this additional staff to handle customer calls and better serve customer inquiries.[26]

At the onset of the storm, the 21st Century High Volume IVR was activated to handle the surge in outage calls in an effort to collect basic outage information in a timely, efficient, and effective manner, allowing the more critical calls (wire down, police, fire, essential service calls) to be handled by the CSRs. 21st Century allows customers to report their outage using an automated system, and can handle higher call volumes. National Grid monitors call volume and turns 21st Century off and on as needed.[27]

Beginning at 1600 hours on Monday, October 29, emergency calls only were being handled by the call center and normal billing calls were suspended due to the large amount of wire down, emergency and outage calls that were coming in. The center re-opened for all billing calls mid-morning on Wednesday, November 14. For the period October 29 through November 18, a record 1,800,078 calls were received.[28]

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[25] DR 257
[26] DR 257 DR 883
[27] DR 500
[28] DR 287 and DR 580

Although LIPA made a number of improvements in response to Irene, deficiencies persisted in many key areas. Overall, the public considered LIPA's performance during Hurricane Sandy to be an even greater failure than Irene.

16.2 Evaluative Criteria

- Does LIPA have emergency plans that are current, comprehensive, reflect actual experience during storms and other emergencies and in compliance with industry practices and are updated periodically?
- Do disaster or emergency response plans consider events affecting a significant portion of LIPA's system?
- Does LIPA have adequate procedures for dealing with facility flooding or other storm-related events? Do emergency plans include mitigation measures for vulnerable facilities?
- Does LIPA's emergency plan include roles and actions required of customer call centers and other customer service resources and is there sufficient and timely information available to these resources?
- Are outage lessons learned reflected in modifications to disaster or emergency restoration plans, training, staffing, system planning or response requirements?
- Do comprehensive and coordinated communication plans exist for disseminating information to customers, local officials, state agencies and the public before and during an emergency outage?
- Are the means of communication between departments within the LIPA organization and between LIPA personnel and outside service providers sufficient to meet emergency needs?
- During an emergency is information communicated to customers, the call center, employees, state and local officials, emergency responders and the public accurately and in a timely manner?

16.3 Findings and Conclusions

16.3.1 With the exceptions of flooding and a major event affecting the call center as discussed below, LIPA has a robust set of emergency plans that are comprehensive, appropriately maintained and reflect actual experience during storms and other emergencies.[29]

- Current ERIPs are a comprehensive set of procedures that address both communications and operations.
  - Section 1 of the ERIPs contains procedures that describe the efforts taken during storm restoration that deal with typical operations activities. Among these are storm anticipation, mobilization of personnel, obtaining foreign crew support, estimating storm damage and restoration time, command and control, safety and lodging and staging of crews.

[29] DR 123

- Section 2 contains procedures that focus on communications within the restoration organization and with other key stakeholders. This includes activation and deactivation of key personnel and organizations, receiving and processing municipal calls, communications with LSA customers, and call assistant and CSR instructions.
- Section 3 contains procedures that describe the operations of the Restoration Operations Center. These procedures cover activation, staffing at the center, release of information and other critical functions.

- The ERIPs evolved from the emergency restoration procedures developed by LILCO in the late 1980s as a result of that company's experience with Hurricane Gloria.

  - The ERIPs were significantly revised to incorporate lessons learned by the utilities affected by Hurricane Katrina in 2005.
  - National Grid made major modifications to the ERIPs following the March 2010 Nor'easter and Hurricane Irene in 2011.
  - The ERIPs are being revised based on the experience with Hurricane Sandy in 2012. Revisions are expected to be made to incorporate all lessons learned from that storm. As of May 2013, the revisions were not available for NorthStar's review.

- The ERIPs are intended to be simple, flexible and easily adapted to specific storms of varying sizes.

- The procedures generally adhere to normal operating procedures with regard to fieldwork and repairs.

16.3.2 National Grid's ERIPS consider events affecting a significant portion of LIPA's system.

- National Grid has procedures for responding to a Condition I – Red event, which address a storm affecting a significant portion of LIPA's system.

- There are three events that trigger a Condition Red: 1) foreign crews are deployed; 2) one or more substation is opened up for rapid survey; or, 3) one or more substations are under SDA.[30]

16.3.3 LIPA and National Grid do not have adequate procedures for dealing with facility flooding; nor do emergency plans include mitigation measures for vulnerable facilities.[31]

- None of the current ERIPs address facility flooding. In DR 722 NorthStar specifically requested any procedures related to flooding. LIPA was unable to respond to this data request.

[30] DR 264
[31] DR 257

- Many of LIPA's substations experienced significant flood damage as a result of Sandy. There were 50 separate substation outages, including 13 which were de-energized due to flooding or mandatory evacuations.

- The flooding also impacting National Grid's gas system on Long Island, meaning that approximately 150 gas personnel with electric survey assignments and 300 gas personnel with low voltage electric repair crew assignments were initially unavailable to participate in the damage assessment or other storm response support activities. Gas personnel became available as gas restoration work was completed.

- While all the substations were expected to be returned to service in pre-Sandy configuration prior to summer 2013, not all equipment at those substations can be returned to pre-Sandy condition before the summer, making these substations higher risk areas from a reliability perspective. Moreover, recent experience has shown increased equipment forced outage rates associated with equipment exposed to salt water.

- National Grid concluded that the risk of flooding can be minimized with additional storm hardening. An internal task force has started to analyze various long-term mitigation proposals including installation of new substations in the respective areas, re-building and raising the elevations of the existing substations, and establishing redundant transmission and distribution in those areas. The feasibility, staging, and implementation of a long term mitigation plan will be based on several factors including the availability of FEMA mitigation funding.

16.3.4 LIPA's emergency plan appropriately describes the actions and responsibilities of the customer call center.

- ERIP 2.2.5, Call Center Operations during Emergency Conditions, issued in September of 2012, specifically addresses customer call center procedures during a major storm or other emergency.

- The purpose of ERIP 2.2.5 is to ensure adequate staffing levels in the call center and to describe the operation of the call center under storm or electric emergency conditions. The procedure provides implementing action checklists to those individuals responsible for the operation of the call center under emergency conditions.

- The procedures provides guidance for actions to be taken prior to, as well as during, an emergency.

- Policies outlined in ERIP 2.2.5 include the decision to augment the call center staff, responsibilities of key people during a major storm or emergency and checklists for:

  - Call center Director
  - Operations Managers
  - Scheduling and Contingency Coordinator
  - Logistics Coordinator

- Communications Coordinator
- Area and Training Co-Coordinators
- Telephone Representative
- Call Assistant
- Call Out Administrator

- Included in the Telephone Representative Checklist is a script for call handlers during initial stages of a major storm and directions for handling difficult calls. [32]

16.3.5 Current storm emergency response plans do not adequately address the potential inoperability of the Melville call center in the event of/during a storm.

- LIPA's business continuity plan addresses an incident or interruption to LIPA's business operations including the call center.[33] The plan uses the Hewlett Training Center as the recovery site.[34]

- The Melville call center is typically staffed with a peak of 100-120 staff. If all phones in the building are utilized, National Grid can access between 350 to 360 seats with phones. During Sandy, all seats in Melville were used to handle the call volume.

- The Hewlett Training Center has 56 working stations (phone and computer) and another 33 computer-only stations as of March 2012. Interviews place the number of seats at closer to 94. This capacity is insufficient to handle call volume of the levels experienced during Irene and Sandy.[35]

- Call center agents and supplemental staff answered four to five times as many calls as typical during Sandy and the Nor'easter, as shown in **Exhibit 16-3** which provides average weekly call volumes for 2012.

Exhibit 16-3
Agent Answered Calls and Abandon Rate
(Weekly Average)

Period	Number of Calls Answered by an Agent	Calls Abandoned
January 1 – October 27, 2012	43,045	2,380
Week of October 28, 2012	234,785	24,475
Week of November 4, 2012	168,800	52,000
Week of November 11, 2012	97,523	2,241
Remainder of Year	55,905	5,376

Note: Sandy is highlighted in yellow.
Source: DR 580 Supplement

[32] DR 263
[33] DR 662
[34] 2012 Business Continuity Plan p. 10 (DR 662)
[35] Interviews (IR 154, and IR 191) place the number of seats higher-approximately 94. The Hewlett facility was not affected by Sandy.

- The Hewlett Training Center was not built for high call volume. It uses an IP network, resulting in a degradation of call quality if the volume gets too high.[36] National Grid addressed this issue during Sandy by using a number of alternative phone lines and services that increased call capacity.

16.3.6 Comprehensive communications plans exist for disseminating information to customers, local officials, state agencies and the public before and during an emergency outage.

- National Grid maintains an Emergency Communications Manual for Condition Red Storms (Section 2 of the ERIPs). The communications ERIPs were updated in mid-2012 as a result of Hurricane Irene and are currently being updated to reflect lessons learned from Sandy.[37]

- ERIP 2.3.1 establishes a Communications Coordination Team (CCT) responsible for developing core messages to be used to support the development of all forms of outbound communication and talking points to be disseminated to customers, media outlets, governmental and municipal communications, major accounts, critical facilities, LSA customers and employees. LIPA's Customer Services Coordinator and National Grid's Chief Communications Coordinator are responsible for coordinating development of content with approval of all messages by LIPA.[38]

- ERIPs 2.1.1 and 2.3.1 define the roles and responsibilities of various National Grid and LIPA individuals. ERIP 2.2.1 and 2.2.3 provide pre-storm checklists for the Chief Communications Coordinator, and checklists for activating and deactivating the CCC. ERIP 2.2.2 provides the notification requirements and phone team. CCC Support Staff Checklists are provided in ERIP 2.3.3. ERIP 2.2.4 addresses the operation of government relations in the CCC.

- Specific ERIPs provide procedures addressing communications with various customer segments. ERIPs 2.1.1 and 2.3.6 address notification and communication with LSA customers. Outbound calls are made beginning 48 hours prior to and during and after a Condition Red event. ERIP 2.2.5 provides procedures for the operation of the call center. ERIP 2.3.2 addresses the municipal calls. ERIP 2.3.4 provides procedures and checklists for communication with critical facilities such as hospitals, nursing homes, schools, water pumping/sewage treatment and the Long Island Railroad (LIRR) and other major accounts leading up to and during the storm.

- ERIP 2.2.8 and 2.3.1 provide customer messaging checklists, storm messaging templates (pre-storm, Day 1 and 2, Day 3+, post-storm), and a defined daily communications timeline for the distribution of messages.

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[36] IR 191
[37] DR 263
[38] Current procedures reflect operations at the beginning of Sandy. New procedures shifting control to National Grid/PSEG-LI are under development.

16.3.7 Although communications responsibility has transitioned to National Grid, current ERIPs do not yet reflect this.

- In accordance with the September 2012 ERIP, the National Grid Chief Communications Coordinator has "joint responsibility with the LIPA Customer Service Coordinator, for the CCC emergency response and coordinating the development of the content of the core message to be utilized by the Communication Coordination Leads to create the various forms of communications and information to be disseminated to stakeholders." The LIPA Customer Service Coordinator had responsibility for approval of messages. [39]

- The April 19, 2013 Final Draft ERIP 1.1.21 "LIPA Headquarters (HQ), Communications Command Center (CCC) and Operations (OPS) Teams" still has LIPA as the single point of contact for the media.[40]

16.3.8 LIPA and National Grid made a number of improvements to the emergency response procedures in response to Hurricane Irene; however, additional improvements are possible. Additional improvements are planned based on Hurricane Sandy.

- As a result of lessons learned from Hurricane Irene, LIPA and National Grid:
  - Began the process of integrating LIPA's and National Grid's emergency response procedures. Prior to Irene, each entity maintained its own procedures.
  - Added four Government Affairs District Manager positions, implemented municipal calls and added a LIPA representative at the EOCs.[41]
  - Merged the operations and communications calls which were held twice daily.
  - Implemented a daily call of all the SACs.
  - Changed the municipal number and asked that officials not hand the number out to the public.[42]
  - Forwarded all LIPA Headquarters calls to the Melville call center.
  - Began setting expectations on potential ETRs before storms hit and developed an ETR timeline/template.
  - Upgraded the "1-800" number to increase bandwidth.[43]
  - Improved communications between the substations and LIPA Headquarters: 38 substations were outfitted with high speed Ethernet/fiber capability; each substation leader was given an air card and laptop; the outage management system was added to the employee work laptops; and, all substation computers were provided with access to the corporate network so people could log into email.[44]

[39] ERIP 2.1.1 (DR 263)
[40] DR 264
[41] IR 32 and 62
[42] IR 25
[43] DR 257
[44] IR 32, DR 257

- Improved visibility to jobs being performed at the substation level when operations move to local substation control through the SDA process.[45]
- Increased the focus on clearing major roads.

- Not all of the recommendations identified in the DPS Irene Audit were implemented.

- Although post-Sandy ERIPS had not been finalized as of May 2013, changes to be made in response to Sandy included:

  - Conversion to a single incident command structure.
  - Development of a single set of emergency response procedures which incorporate LIPA personnel into the National Grid structure.[46]
  - Added mainframe capacity and bundled data to accommodate higher volumes of data.[47]
  - Added trunks to the call center to increase call capacity.
  - Transition to daily regional municipal calls (four- regions), as opposed to single calls, to communicate more geographically specific information.
  - Added Divisional Liaison positions to assist in the collection of outage, crew and ETR data and improve information from the substations, although this process had not been fully defined as of June 2013.[48]

16.3.9 LIPA has not appropriately incorporated lessons learned from storms into its storm hardening program in order to minimize the potential effects of major storm.

- In 2006, LIPA adopted a proactive storm hardening policy and plan to address the threat of severe storms, including hurricanes. This long-term program was anticipated to cost up to $500 million over 20 years to improve the capability of the electric system on Long Island to withstand the impacts of hurricanes and other severe storms, and to shorten the time required to restore service to customers when outages occur due to storms.

- The storm hardening plan included:

  - Specific programs/projects to address critical infrastructure.
  - Specific projects to address flood prone/surge areas, including protecting substations from flooding and storm surges, and reinforcement of site specific areas prone to flooding.
  - Incremental spending on system reinforcement projects to increase strength of infrastructure, and reinforced foundations to support critical equipment and structures.
  - More robust steel infrastructure.
  - Stouter poles and replacement of deteriorated poles.

[45] DR 257
[46] DR 264
[47] IR 62
[48] Various interviews, DR 269

- Enhanced right of way maintenance, removal of danger trees adjacent to lines, accelerated tree trim cycles in areas prone to storm damage, additional tree trimming commitment for both distribution and transmission programs, and expanded transmission rights of way to provide additional clearance.
- Installation of new underground circuits.
- Reinforced substation foundations and structures to withstand higher wind speeds.
- Strengthening of selected poles and lines to withstand higher wind speeds and storm-related flooding.[49]

- Despite the 2006 plan, Hurricane Irene and Hurricane Sandy did extensive damage to LIPA's T&D system. Both storms resulted in damage caused by strong winds, heavy rain and flooding.

- LIPA's Irene After Action Report identified two significant vulnerabilities: the potential for substation floods and the potential for significant pole line damage which would affect service to a large number of customers. LIPA had planned to study all aspects of the design and operation of the T&D system and identifying areas prone to flooding, including the substations and transmission lines located in those areas.

- LIPA was still in the process of formalizing a multi-year system-wide storm hardening program in response to Irene when Sandy hit. Several substations experienced significant damage due to flooding and the resulting salt water contamination of equipment and control cables. All of the flooded substations were put back into service prior to summer 2013. However, not all of the equipment at each of these substations has been returned to pre-Sandy condition, putting these substations at risk for reliability problems.

- It is unlikely that anyone could have predicted Sandy; however, it is clear that LIPA missed an opportunity to benefit from its lessons learned from Irene. It is clear that Irene raised the possibility of substation flooding. Even if LIPA had expedited plans to mitigate substation flooding, the associated design and construction might not have been completed before Sandy struck. Nonetheless, LIPA should be more diligent in implementing storm hardening initiatives identified by major storms.[50]

- LIPA is currently developing a plan to bring all the flooded substations to pre-Sandy condition within the next two years. Additionally, an internal task force has begun analysis of various long-term mitigation proposals including the installation of new substations, raising the elevation of the existing substations, and establishing redundant transmission and distribution lines. The implementation of a long term plan to mitigate the system's vulnerability to flooding will be based on several factors, including the availability of funding.

[49] DR 60
[50] DR 124 and DR 257

16.3.10 LIPA failed to follow its communications plan in the aftermath of Sandy, increasing customer and elected official frustration, and undermining confidence in its restoration efforts.

- During the past two major storms, the lack of accurate, timely information and public pressure for more specific, customer-level data led to a breakdown in the communications process.

- During Sandy, LIPA failed to conduct daily press conferences as required by its communications plan.[51]

  - Existing communication plans required daily press conferences.
  - Press conferences were not held until November 7, 2012 when LIPA announced the flood zone re-energization process. Subsequent press conferences were held on November 9, 10, 11 and 12.[52] LIPA was not at the press conference held on November 11, 2011, so questions regarding communications (a LIPA responsibility) went unanswered.
  - LIPA and National Grid acknowledge this deficiency in its Sandy After Action Report:

> "LIPA senior leadership made a decision early on to deviate from established communications procedures, electing to employ other communications channels and did not hold a press conference until more than a week after the storm had passed. In retrospect, this proved to lessen the effectiveness of communications efforts. As the days progressed and the ensuing nor'easter lengthened the restoration effort, customer patience was challenged and their expectations regarding outage information grew. And, while the specificity of information provided moved forward from prior efforts, a gap in the information provided and customer expectations still remained."

- As a result of the lack of information, District Managers, elected officials, and sometimes the public began calling or going to substations to attempt to obtain information.[53] Others with headquarters responsibilities went into the field to try to obtain and help relay information.

16.3.11 Despite lessons learned from Irene, LIPA and National Grid were unable to provide specific enough ETRs or progress updates to meet the needs and expectations of its customers and government officials during Sandy. Information was neither timely nor necessarily accurate.

[51] IR 208, Sandy After Action Report, various interviews and review of media coverage
[52] DR 257, review of media coverage
[53] Various interviews, DR 274

- The Irene After Action Report found that LIPA and National Grid's efforts fell short in providing desired restoration information in terms of frequency of updates on progress and projections, visibility to where repair crews were working and customer/area-specific outage restoration information.[54]

- Government officials called LIPA to express frustration with what they perceived as LIPA's inability to provide accurate crew information, having been unable to locate crews that LIPA told them were in their jurisdiction. Similar frustration was expressed during the municipal calls.[55]

- In response to Irene, National Grid instituted the SDA process with the intent to improve customer messaging, provide more customer specific restoration information and increase the visibility of the status of many restoration jobs.[56] It also developed a major event messaging and ETR guideline; however, this did not result in greater specificity during Sandy. **Exhibit 16-4** provides the revised ETR guidelines.

Exhibit 16-4
Major Event Messaging and ETR Guideline

Day	Global Message	CARES Message	ETRs
Pre-Storm	As per template - estimate of x to y days	Daily Normal Conditions	N/A
Day 1	As per template	Special Storm Message (System/Division)	Do not give out final restoration day or 90% by xx date. Give out historical information. Very remote possibility of giving out ETRs.
Day 2	As per template, more data and description than Day 1	Initial General Storm Message or Increased Activity Default Message (Division)	Provide progress against historical. May be able to give global ETR for all of LI. Remote possibility of giving out ETRs – job must be polygoned with assurance that bulk of customers restored. For customers in polygon, information avail. to call center.
Day 3	As per template, more data and description than Day 2	Full Restoration General Storm Message (Division/Console/Substation)	Provide global ETR for all of LI. AM – initiate ETR polygon jobs. PM – initiate ETRS for polygons per substation local control procedures. Initiate substation-level ETRs. For customers in polygon, information avail. to call center.
Day 4	As per template, more data and description than Day 3	Full Restoration General Storm Message (Division/Console/Substation)	Continue polygon ETRs. Continue substation ETRs. For customers in polygon, information avail. to call center.

Source: IR 32 and DR 265

[54] DR 124
[55] Various IRs DR 274
[56] DR 257

- Despite these improvements, during Sandy LIPA was unable to provide customer-specific ETRs until roughly a week after Sandy made landfall.[57] **Exhibit 16-5** provides the actual Sandy messaging timeline.

Exhibit 16-5
Sandy ETR Messaging Timeline

Day	Dates	ETR Message	Flood Zone
Pre-Storm	October 27-28	As per template - estimate of x to y days	N/A
Day 1	October 29	Unprecedented damage	N/A
Day 2	October 30	Unprecedented damage	N/A
Day 3	October 31	Repairing the system backbone	CSR Talking Points: Customers may need electrical inspection and certificate
Day 4	November 1	Repairing the system backbone	CSR Talking Points: Flood areas require coordination with local officials; may take longer to restore
Day 5	November 2	Repairing the system backbone	
Day 6	November 3	700,000 by 11/4 and 90% by 11/7	CSR Talking Points/IVR/Web: LIPA is working with local officials
Day 7	November 4	700,000 by 11/4 and 90% by 11/7	CSR Talking Points/IVR/Web: LIPA is working with local officials; we are developing a plan
Day 8	November 5	700,000 by 11/4 and 90% by 11/7	CSR Talking Points: LIPA is working with local officials; need for electrical inspections; special task force deployed
Day 9	November 6	700,000 by 11/4 and 90% by 11/7 Crew numbers by substation area	CSR Talking Points/IVR/Web/Press Release: Hire an electrical contractor; surveys being performed
Day 10-12	November 7-9	Prepare for additional damage due to Nor'easter Crew numbers by substation area	Flood zone process PSA, press release, website, call center, onsite presence and social media
Day 13	November 10	Outbound calls to areas where power should be restored Crew numbers by substation area	Flood zone process PSA, press release, website, call center, onsite presence and social media
Day 14-16	November 11-13	Outbound calls to areas where power should be restored Substation level estimates (non-flood)	Flood zone process PSA, press release, website, call center, onsite presence and social media
Day 17	November 14	Outbound calls to areas where power should be restored Most customers restored, if still off 24-48 hours	Flood zone process PSA, press release, website, call center, onsite presence and social media

Source: DR 257

- Based on a small sample of call center calls,[58] initially National Grid told customers to prepare for seven to ten days without power (an improvement over Irene). On November 2, National Grid was unable to provide ETRs as restoration had really "only begun 36 hours ago". Calls listened to from November 5 and 6 had some estimates, but not consistently. By November 8, restoration estimates

[57] Various interviews. The Moreland Commission found a similar problem among the IOUs.
[58] 35 calls

were more consistently available.[59] Initially the call center had information such as the location of downed poles, but according to call center personnel and the review of calls, once National Grid went to local control, the call center lost that level of detail.[60]

- On the November 7, 2012 afternoon municipal call, callers expressed frustration with the lack of ETRs and the fact that in certain areas they did not know if it would take months, weeks or days to be restored.[61]

- On November 7, 2012, Long Island was impacted by a nor'easter resulting in 123,000 customer outages in addition to the remaining Sandy outages.

  - As the result of the damage caused by the nor'easter, damage assessments had to be redone, work was re-prioritized and new ETRs developed.
  - On the November 7, 2012 afternoon municipal call, callers expressed frustration with the lack of ETRs and the fact that in certain areas they did not know if it would take months, weeks or days to be restored.[62]

- As had been the case with Irene, LIPA and National Grid acknowledged that Sandy "efforts fell short in providing the desired restoration information in terms of specific detail on outages, timeliness and clarity of information regarding the process for re-energization in flooded areas and a general awareness setting of the level of damage suffered by the transmission and distribution system as a result of this catastrophic storm."[63]

16.3.12 LIPA was not prepared to communicate appropriate information regarding restoration of service to customers whose homes had been flooded.

- Severe flooding along the south shore of Long Island and in the Rockaways also damaged an estimated 100,000 homes and businesses. Saltwater intrusion to electrical panels, electrical outlets and wiring made it unsafe to re-energize affected premises without proper inspection and any necessary customer repairs. In such instances, the responsibility to inspect the flooded homes and businesses to determine those that were safe to energize was that of the local municipality. Given the large amount of flooding and the number of local jurisdictions involved, the efficiency of these efforts varied across the service area.

- Many customers who could not be reenergized as a result of damage to their homes were not informed until well after the restoration efforts had begun.

- LIPA did not have appropriate messaging to provide to customers until November 7. While the responsibility for inspection does not rest with LIPA, these service lines are

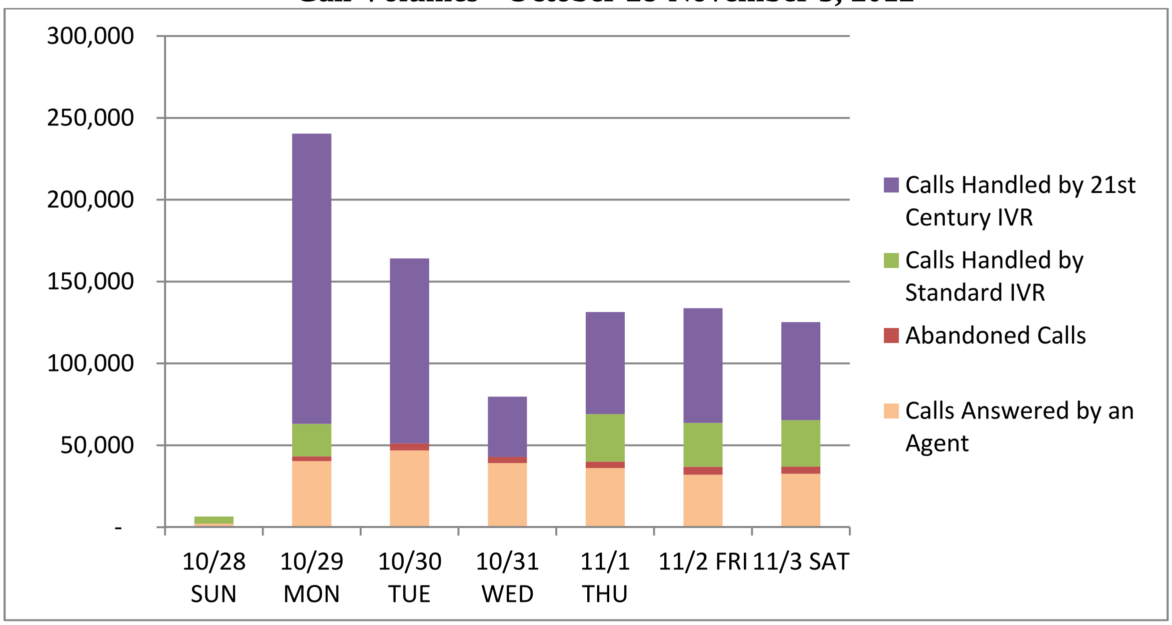
[59] IR 188
[60] IR 188
[61] Call transcript (DR 274)
[62] Call transcript (DR 274)
[63] DR 257, p. 80

part of LIPA's electric system. LIPA held a press conference on November 7, 2012 where the media questioned the timeliness of the notification.[64]

16.3.13 At times during Sandy, facilities limitations prevented customers from being able to contact LIPA.

- During Hurricane Sandy and the Nor'easter, LIPA's contact experienced an unprecedented level of calls with a daily volume of all calls in excess of 200,000 at the peak. **Exhibit 16-6** provides call volumes for the period October 28-November 3, 2012. Sandy made landfall on October 29, 2012.

Exhibit 16-6
Call Volumes - October 28-November 3, 2012



Source: DR 580

- There are 575 talk paths/trunks into Melville. If all trunks are busy, customers will receive a "fast busy" signal. This proved particularly problematic from November 6 to 9 when all trunks were busy for a portion of the time as shown in **Exhibit 16-7**.[65]

- To address this problem, National Grid utilized a number of alternative phone lines and services that increased capacity. Those lines were kept available for high call volume days post-Sandy.[66]

- Following Sandy, National Grid has not added any additional trunks to Melville as they are seat-constrained and may run also into switch constraints.[67]

[64] http://fios1news.com/longisland/node/21776
[65] Although National Grid can detect the trunks are busy, it cannot detect the number of busy signals. According to National Grid, prior to Sandy it rarely ran into an all trunks busy condition. (DR 580)
[66] DR 540
[67] IR 191, DR 540

Exhibit 16-7
All Trunks Busy (Huntington Group 1 to 11)

Date	Percent of Time All Trunks Busy
11/6/12	45.74
11/7/12	53.73
11/8/12	47.86
11/9/12	28.03

Source: DR 867

- LIPA does not use at-home call center agents or any outsource service providers. As a result, during a major event such as Sandy, it has few places to offload a portion of its call volume.[68]

- The number of desks with phones and computer access to the CAS and CARES system can become a limiting factor. At maximum capacity, Melville can house about 350 agents using all phones in the building.

- The rest of National Grid's operating companies do not use the same systems as LIPA (CAS and CARES), limiting National Grid's ability to use staff from other National Grid jurisdictions to provide additional resources.

16.3.14 As a result of Hurricane Sandy, storm communications responsibility was shifted from LIPA to National Grid, which better aligns accountability for both restoration and communications with stakeholders.

- Until midway through Sandy LIPA retained responsibility for storm communications.

- During Sandy, National Grid was asked to take on additional responsibility and assumed complete responsibility during Nemo in February 2013.[69]

- As a result of the change, the organization responsible for the restoration and the development of ETRs must now answer to the media, customers and other stakeholders.

16.3.15 PSEG-LI is in the process of addressing high-risk areas in the existing storm response process and has plans to replace the existing CARES system.

- During the transition period, PSEG-LI is working with LIPA in the review of the current storm process and implementation of changes with the intent to establish control points and increasing accountability.[70] The team is focusing on improvement opportunities in three critical areas: resources, communications and maximizing the number of customers restored within 72 hours of the storm event.[71] Future storm

[68] 2012 Business Continuity Plan p. 20 (DR 662) and various interviews
[69] IR 20 and review of media coverage
[70] To-be Brainstorming Session (IR 60)
[71] To-Be Presentation (DR 259)

response plans must account for the loss of National Grid's Long Island gas employees as part of the storm response resources.

- Topics under review included expansion of the mutual assistance crews and the timing of requests, storm jobs, centralized versus local control, information flow and ETR availability, consistency of information, revised communications timelines based on the media news cycle; controls to minimize the number of individuals responding to the same requests, accountability and the approval of information to be released.

- PSEG-LI's review identified about 80 issues and 28 immediate risks to be addressed prior to January 1, 2014, including the following:[72]

  - Storm calls at Hicksville appear to lack clear, accurate, and timely outage data (e.g., number of customers out, crews in region, site safety issues, ETRs).
  - Accountability is unclear - corporate and customer communications aren't separated in National Grid/LIPA model.
  - Apparent lack of single point of contact for media relations, data requests and interviews.
  - Due to lack of key data points from storm calls, public affairs (email, phone, etc.) messaging may not be optimized.
  - Ability to report ETRs and customer counts under local control is lost since SDA still needs improvement.
  - Prior to SDA, the Division lost sight of activity at Substation and ETR reporting was unavailable through CARES once in local control. SDA still needs improvement.
  - Once in local control, Division/Hicksville lost sight of damage locations at substation in CARES.
  - Accurate restoration data (e.g., number of outages, ETRs, crew locations) from Operations and Communications calls is often unavailable, delayed or inconsistent.
  - Damage assessment carried out in the field using paper based data capture and entered into the Outage Management System (OMS) manually.
  - Lack coordinated process to address/prioritize wire down -- poor coordination with municipalities.

- PSEG-LI is working to address the 28 areas identified as high-priority risks by January 1, 2014.

- According to PSEG-LI, the implementation of a GIS Connected Model as a replacement for the existing polygon-based CARES outage analysis system, in conjunction with the integration of existing SCADA, IVR, HVCA, Web and iFactor into the OMS [outage management system], will allow LIPA to more accurately and efficiently identify, prioritize and communicate outages.

[72] DR 259

- The proposed OMS solution provides for integration of these various data sources so that many of the current manual processes can be eliminated, enabling storm managers to make more effective decisions.[73] As of March 2013, the system is scheduled to go live July-2014.

- As the system has not yet been developed, NorthStar is unable to determine the extent to which it will mitigate problems during a storm event of the magnitude of Sandy. Consolidation of the information available in the SCADA, IVR, HVCA and other systems should prove beneficial; however, the challenge will still be to get the information into the systems in the first place.

  - As an example, if a primary distribution line going out from a substation is cut by a fallen tree, SCADA will be able to show that the line is disconnected, and that several hundred customers (however many are served by the line) are out of power. Unfortunately, SCADA will not know what caused the line to be out, so SCADA will not be able to generate an estimate that says, "If we remove the fallen tree (two hours) and put the line back up (two hours) we will have service restored in four hours".
  - Beyond that, SCADA will not know if there is other damage farther down the line. Repairing the first break will probably not restore all of the customers affected, because in a major storm there will likely be other damage. Nonetheless, repairs normally begin at the substation and move toward the customers. Information from the IVR, such as customer calling to say they can see a tree across a line (a downed line) will also help, but customers won't see all of the damage either.
  - It is unlikely that the integration of information from all of the available automated systems will replace the need for a complete walk down of every line during a major storm.

16.4 Recommendations

16.4.1 For the current (2013) storm season, develop procedures to address lessons learned from Sandy, including: expedited implementation of storm hardening initiatives; plans for handling increased call volumes, possible failure of the call center and possible flooding of LIPA assets; interim improvements to address deficiencies in the ETR process; confirmation of responsibility for storm communications and commitment to follow the communications plan; and provision of shelter lists and guidance to customers responding to broader system conditions caused by flooding, such as inspecting customer premises and authorizing the reenergizing of homes and businesses.

16.4.2 Review and update as necessary, procedures to adequately address the possibility of flooding in areas that may be affected by future storms or emergencies. The procedures should include not only preventive measures, but should also provide guidance for responding to broader system conditions caused by flooding, such as

[73] BOT presentation DR 327

inspecting customer premises and authorizing the reenergizing of homes and businesses.

16.4.3 Review and update as necessary, the business continuity plan to include failure of the call center due to or during a major storm event.

16.4.4 Ensure the ERIPs accurately reflect the responsibility for storm communications.

16.4.5 Continue to expedite the implementation of storm hardening initiatives identified based on prior storm lessons learned, including Sandy.

16.4.6 When under emergency conditions, consistently follow the communications plan and provide customers with regular updates (including press conferences) even if limited information is available.

16.4.7 Implement appropriate improvements to address deficiencies in the ETR process for future storm seasons.

- The lack of valid ETRs, initially as well as updated or revised versions, continues to be a major reason for customer dissatisfaction.
- Current plans include the addition of liaison positions responsible for collecting data from the substations and transmitting it to headquarters for consolidation and distribution to the various communications channels. LIPA must be prepared to dedicate the necessary resources to gather information regarding the causes and requirements for restoration of all outages, immediately following a storm and continuously as the restoration effort proceeds.
- Integrating and/or expanding systems that support storm restoration may help. However, developing and communicating valid and dependable ETRs requires a focused effort on damage assessment and monitoring progress toward restoring customers. Ample resources must be dedicated to this job.

16.4.8 Implement remaining outstanding open recommendations identified in the DPS Audit of LIPA/National Grid's Hurricane Irene Response and issues identified in the Sandy After Action Report. Develop a formalized process for tracking implementation progress.

16.4.9 Develop more robust plans for handling the call volumes possible during a major storm.

- Conduct a cost-benefit analysis of the use of at-home agents and outsourced call center services located off Long Island to increase efficiencies and reduce costs (in the case of outsourced resources), and to increase the number of supplemental resources trained in the use of LIPA's systems who would be available to handle call volume during storm events.

- On an ongoing basis, assess the need for additional call volume capacity to the call center (i.e., trunks, switches and seats). Note: improvements in the accuracy and timeliness of the information provided to customers should reduce call volume.

- Consider the use of call center retirees as supplemental workers in the event of a Condition Red event.

- The call center should obtain customer cell phone numbers and email addresses to facilitate communication in the event of a storm.

- Use customer time on hold to play tailored messages and outage/storm-related information, and provide estimates of hold times.

16.4.10 Review and update as necessary, processes, processes to provide shelter lists to the call center representatives when under emergency conditions to assist customers that may not have the capability to contact FEMA.[74]

[74] DR 274

17. LONG-TERM ENERGY SUPPLY PLANNING

This chapter provides NorthStar's assessment of LIPA's load forecasting, power resource planning, and capacity procurement processes.

17.1 Background

A utility's load forecast is the driving force behind its supply procurement and system planning efforts, and is an important factor in analyses of regulatory, financing, and other strategic planning options. As such, the load forecast affects reliability and the price of supply and operations. LIPA needs to ensure that its load forecasting processes identify and address changing energy and capacity needs, system effects, and market conditions in a timely and accurate manner.

Historical weather and weather patterns determine the main elements of supply procurement forecasts for the electric peak-hour forecast. Other factors for developing accurate load forecasts include incorporating energy efficiency savings and trends in use per customer. The effectiveness of the load forecasting function can be measured by comparing forecasts with actual requirements. The integration of information and the commonality of assumptions are critical to weather and economic scenario development and ultimately lead to probabilistic modeling of worst case conditions.

LIPA experienced a slight decrease in sales during 2008 and 2009. This can be attributed to the general economic downturn of the region and the impact of the first year of LIPA's Energy Efficiency Long Island Plan (ELI) in 2009.[1] In 2010, total sales began showing growth due to a general increase in residential sales and a modest recovery in the commercial and industrial sectors. LIPA's coincident peak demand has fluctuated over the past six years and has exhibited a 0.5 percent trended growth rate from 2007 through 2012. **Exhibit 17-1** provides details on LIPA's annual system sales and coincident peak demand.[2]

Exhibit 17-1
LIPA Historical Electric Sales

Year	Total Sales (GWh)	Normalized Sales[3] (GWh)	Growth (Percent)[4]	System Peak (MW)	Normalized Peak (MW)	Growth (Percent)
2007	20,093	20,182		5,247	5,239	
2008	19,888	20,135	-0.23	5,130	5,284	0.86
2009	19,271	19,736	-1.98	5,034	5,208	-1.44
2010	20,320	19,886	0.76	5,719	5,303	1.82
2011	20,248	20,147	1.31	5,783	5,269	-0.64
2012	19,954	20,297	0.74	5,348	5,341	1.37

Source: DR 392

[1] LIPA reported 118 GWh of energy efficiency savings in 2009 and an additional 143 GWh in 2010 (DR 346).
[2] DR 392
[3] Normalized indicates an adjustment from actual weather to normal weather.
[4] Change in weather normalized sales from previous year.

Between 2007 and 2009, the commercial and industrial sectors led the decline in electric sales and have not recovered to their 2007 levels. **Exhibit 17-2** provides sales by rate class sector.

Exhibit 17-2
Weather-Normalized Sales by Sector

Year	Residential (GWh)	Growth (Percent) [5]	Com/Ind (GWh)	Growth (Percent)
2007	9,553		10,177	
2008	9,673	1.26	9,998	-1.76
2009	9,534	-1.44	9,742	-2.56
2010	9,638	1.09	9,795	0.54
2011	9,755	1.21	9,810	0.15
2012	9,904	1.53	9,841	0.32

Source: DR 392

LIPA has three distinct periods in its forecasting platform:

- The five year forecast (midterm) – a least-squares regression model and spreadsheets adjusted for externalities (such as energy efficiency, co-generation, LI Choice, and wholesale municipalities) to forecast annual sales. LIPA also develops a five year forecast of peak demand for both normal and extreme weather.
- The 20 year forecast (long term) – a trend analysis of the five year forecast
- The day-ahead forecast (short term) – a probabilistic forecast of day ahead sales and hourly demand based on weather forecasts.[6]

While the load forecast is the basis for power supply and capacity planning, a load forecast must be first be converted into a "Need Forecast" which incorporates the losses associated with the transmission system and required targeted reserve generating capacity. To maintain a reliable system, LIPA must either contract or have installed reserve capacity to account for possible forced shut-down of generating units and transmission limitations. In developing its energy resource plans and in procuring its capacity, LIPA must comply with two New York planning criteria:

- **New York State Reliability Council (NYSRC) Total Statewide Reserve Margin Requirements –** This requirement is established annually for a one year period by the NYSRC using a probability based model. Statewide, there must be at least enough capacity to meet the combined projected load of all utilities plus the Installed Reserve Margin (IRM). The IRM requirement is allocated to each load serving entity in proportion to peak load. To prevent over-procurement of resources, LIPA targets keeping long-term contracts at or below its IRM measured with a 50 percent

[5] Change in weather normalized sales from previous year.
[6] DR 176; the short-term forecast is discussed in **Chapter 18 - Power and Fuel Supply Management**.

confidence level. Then LIPA meets the specifics of the requirement every month through purchases from the short-term markets as necessary.

- N**YISO Zone K Locational Requirements –** This requirement is set annually for a one year period by the NYISO using a probability based model.[7] It specifies that Zone K (Suffolk, Nassau and the entire Rockaway Peninsula) must be able to serve the specified percentage of its load (the Locational Capacity Requirement, LCR) from resources qualified as Long Island resources.[8]

Generation capacity planning is a critical step to ensure the availability of resources for the system peak hour. Based on the "Needs Forecast", the utility conducts a Resource Needs Assessment (RNA). RNA compares the "Needs Forecast" against current capacity resources. The RNA is a long-term assessment, typically 10 to 20 years, as generation resources generally have extensive lead times. The lead time involves a number of time consuming processes such as:

- Siting
- Issuance of Request for Proposals
- Contract Negotiations
- Environmental Impact Analysis
- Construction
- Testing and Commissioning

In assessing current capacity against future needs, the RNA includes a number of analyses:

- Capacity shortages based on current inventory of resources
- Compliance with initiatives such as renewable resources and greenhouse gas emissions
- Potential retirements of resources due to age
- Expiration of long-term contracts
- Potential repowering of resources due to environmental and regulatory requirements

Resource planning utilizes both probabilistic and deterministic modeling of long-term capacity requirements. Deterministic models are mathematical models in which outcomes are precisely determined through known relationships among states and events, without any room for random variation.

LIPA utilizes a deterministic model for the local generating unit available capacity at the time of peak demand. In 2013, the available capacity during the peak demand is approximately 6,000 MW. This is reduced from the near 6,700 MW of available capacity due to a combination of forced outages, temperature derating and operational characteristics of renewable resources at the time of the system peak.

[7] DR 62 Appendix B
[8] Zone K includes all of Long Island excluding cogeneration customers and forecast energy efficiency savings.

In comparison, probabilistic models use ranges of values for variables in the form of probability distributions. The coincident peak demand would be considered a probabilistic model where ranges of values for weather, energy efficiency, economic growth etc. would be modeled and probable outcomes would be determined. Results are expressed in confidence levels. LIPA utilizes a probabilistic model for determination of capacity need. The model is an @Risk Excel model developed by National Grid for LIPA. The capacity need is based on an 80 percent probability of meeting requirements level.

LIPA utilizes a production cost model, the GE Multi-Area Production Simulation Software (MAPS) for supply planning and new resource evaluation. MAPS is a detailed, chronological simulation model that calculates hour-by-hour production costs while recognizing the constraints on generation dispatch imposed by the transmission system. MAPS performs a transmission-constrained production simulation, which uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch.[9]

The primary work product from LIPA's supply planning and resource evaluations is a Resource Plan which provides a roadmap of how LIPA plans to meet customer needs over a specified time period. LIPA's most recent formal resource plan is the 2010-2020 Electric Resource Plan (ERP), which was developed based on analyses performed in 2008 and 2009.

LIPA's basic methodology in developing its resource plans is illustrated in **Exhibit 17-3** and consists of the following elements:

1. Reference Case – Compare projected needs against available Long Island Locational Capacity Availability.
2. Determine when and if additional resources are required.
3. Analyze existing resources
   - Contractual expirations
   - Repowering of existing plants
   - Retirements of existing plants
4. Identify new resources. LIPA utilizes a screening analysis to evaluate new resources.
5. Compare alternative power supply plans based on an integrated analysis of selected resource options and assumptions;
6. Develop a probabilistic assessment of each alternative power supply plan; and
7. Determine power supply plan that illustrates one way of pursuing the goals and initiatives contained in the Electric Resource Plan to establish a baseline for comparing alternative plans.
8. Publish the Electric Resource Plan.[10]

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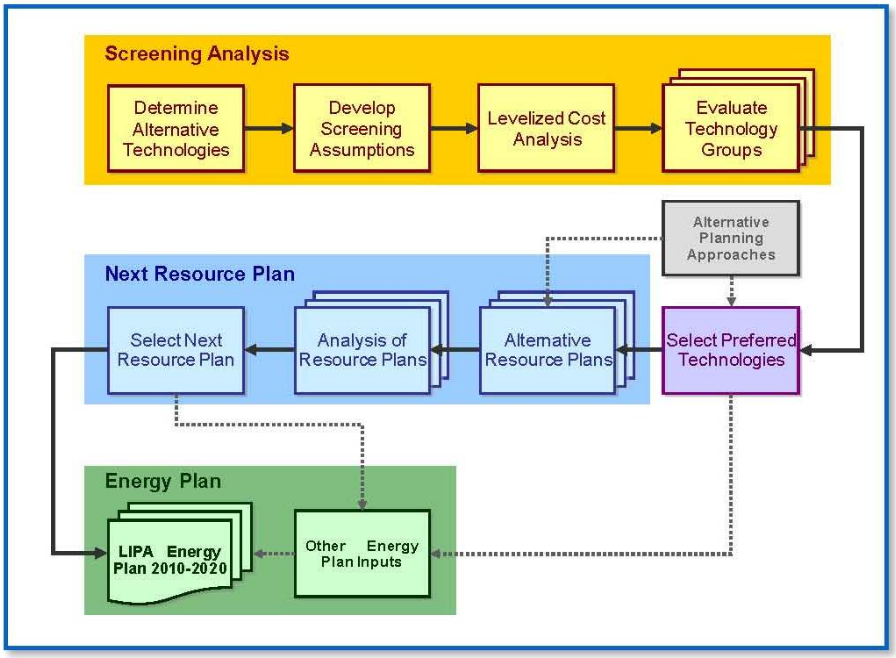
[9] http://www.crai.com/consultingexpertise/content.aspx?tID=828&subtID=842&terTID=896
[10] DR 62 and appendices

Exhibit 17-3
Resource Planning Process



Source: DR 59 Appendix B

17.2 Evaluative Criteria

- Are forecasting and planning functions organized and staffed appropriately?
- Are the models, assumptions, key drivers and other inputs to forecast local and system-wide load requirements appropriate?
- Does LIPA have well-defined forecasting platforms including multiple forecasting horizons, appropriately segmented customer models, and sufficient data sources?
- Are inputs, including demand side management (demand response), energy efficiency, and other similar factors given appropriate consideration in the forecasting process?
- Does LIPA have access to and use best available data to support implementation of energy efficiency, demand response and other initiatives?
- Are planning for electric load and region-specific factors integrated into the overall business processes and strategies?
- Are the LIPA system load forecasts accurate, and are deviations between the forecasts and actual experience investigated and promptly corrected?
- Do the load forecasting functions/products meet the needs of finance and rates, supply procurement, regulatory compliance, system planning and other organizations within LIPA?
- Does LIPA have appropriate supply portfolio principles, goals and objectives for mass market default customers?

- Is LIPA's long term supply planning processes and resulting long term supply plan appropriate and does it result in best cost, reliable long term supply for Long Island electric users?
- Does LIPA have appropriate supply procurement strategies and policies, including diversity of generation sources, the role of the PSA and PPA units, environmental concerns/emissions credits, and use of renewables and demand reduction programs?
- Are the models used for supply planning appropriate, sufficient quality/robust, incorporate appropriate risk (probabilistic) capabilities, scenarios, etc. incorporating uncertainties in fuel pricing, demand, supply, delivery capabilities (cables)?
- Does LIPA have appropriate strategies and practices to incorporate uncertainty relative to supply procurement decisions?
- Is the supply procurement planning process integrated with strategic and operational planning processes?
- Is the role of the NYISO electric capacity markets in the supply planning processes appropriate relative to on-island generation?
- Does LIPA's existing and planned power supply portfolio include the appropriate use of alternate energy sources (e.g., hydropower, wind, energy storage, etc.)?
- Is the role of on-island generation provided by the PSA units effective and efficient? Does LIPA incorporate its long term power purchase agreements with the Long Island generating facilities (PPA and renewables) into its Long Term Supply Plans to the benefit of ratepayers?

17.3 Findings and Conclusions

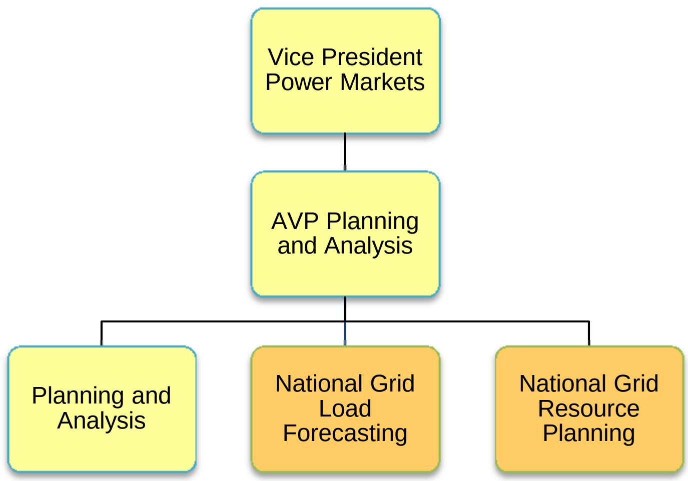
17.3.1 LIPA's forecasting and planning functions are organized and staffed appropriately.

- LIPA's energy resource planning and power market policy development is the responsibility of its Planning and Analysis group, which is part of the Power Markets Department. The actual load forecasting and resource planning modeling functions are performed by National Grid's Load Forecasting and Resource Planning groups, as shown in **Exhibit 17-4**.
  - The AVP of Planning and Analysis and the Director of Planning and Analysis are responsible for overseeing LIPA's long-term planning (needs assessment and resource alternatives analysis) and financial analysis.[11] They provide the interface between the LIPA energy planning activities and the National Grid modeling groups.
  - National Grid's Load Forecasting and Resource Planning groups are part of the dedicated Network Strategy Planning organization, which also supports other system planning and analysis functions for LIPA. Load Forecasting is staffed with one manager and two analysts. Resource Planning is staffed with a section manager, a lead engineer and three staff engineers.

[11] DR 344

- All the personnel involved in the forecasting and planning analysis are experienced with the tools they use and LIPA's system and generating assets and options.

Exhibit 17-4
Forecasting and Energy Planning Organizations



Source: DR 344; DR 2.

17.3.2 National Grid provides LIPA with a sophisticated resource planning platform and experienced personnel that collectively support requisite analyses for both load forecasting and energy supply planning for LIPA.

- National Grid's Resource Planning group is the backbone for all of LIPA's reference, scenario, and contingency analysis.

- The group maintains extensive databases that model all available generating units and transmission system load capabilities. Their modeling include capabilities include:

  - Probabilistic and deterministic analyses for capacity needs.
  - Production cost modeling for energy planning.
  - Economic analysis for scenario support.

- National Grid can provide numerous scenarios and confidence levels.

- The interactions and communications and coordination between LIPA and National Grid regarding load forecasting and system planning are very well coordinated and the groups for the most part function as if they were in one organization.

- As of July 2013, it appears that the National Grid load forecasting and resource planning functions will be moved into two separate groups in ServCo. The future location of the LIPA Director of Planning and Analysis was not clear.[12]

17.3.3 LIPA has an overall power supply and energy planning strategy that is generally appropriate, although strongly influenced by social benefit objectives; the development of a guiding resource plan is incomplete.

- LIPA's resource planning activities are driven by five goals:[13]

  - Reliability - Meeting the reliability requirements of the NYISO, the NYSRC and internal reliability requirements.
  - Cost - Improve operating efficiencies that will reduce customer bills.
  - Energy Efficiency – Pursue a cost-effective strategy and plan for reducing electricity use by 15 percent in 2015.
  - Renewable Resources – Pursue cost-effective strategy and plan for increasing LIPA's mix of renewable energy and support efforts to obtain a 30 percent Renewable Portfolio Standard by 2015.
  - Greenhouse Gas (GHG) Reduction – Develop strategies for reducing greenhouse gas emissions to a level of 20 percent below 2005 levels by 2020.

- The first two of these are typical and expected planning goals to meet reliability requirements in a cost efficient manner

- The next three goals are driven by environmental and social benefit desires and public policy goals. While most utilities incorporate energy efficiency, renewables and reductions in greenhouse gas emissions into their planning efforts, these desires typically do not comprise three-fifths of an organization's resource planning goals.

- LIPA refers to the ERP as the official documentation of its future resource plans. However, as approved by the LIPA BOT, the ERP is not a typical electric supply resource plan, in that it does not clearly convey future needs or how the need will be met with specific resources at a specific times. Instead, it implies a very high reliance on broad energy efficiency and renewable energy aspirations.

- There is minimal assessment of the feasibility of achieving the efficiency and renewables goals, nor is there an action plan for implementation.

- The ERP does not include identification of the cost to achieve its plan for future energy supply.

- The Authority never completed the intended Action Plan to implement and monitor achievement of the goals set forth in the ERP.

[12] DR 2 and DR 351
[13] DR 62

17.3.4 Despite the shortcomings of the ERP, LIPA has made informed and appropriately supported decisions regarding future energy supply needs as a result of modeling and analysis outside of the ERP.

- The Resource Planning group performs studies and analyses of a wide variety of supply options, including the issuance of three RFPs for new capacity and several repowering and retirement analyses. Resource planning continues to update its energy supply planning studies on an almost continuous basis.

- LIPA's planning group is aware of the likely investment that an aggressive pursuit of the specific energy efficiency, renewables, and GHG goals would entail. There is an appropriate balancing of cost and progress towards achievement of the social benefit goals.

- NorthStar found LIPA's procurement of new resources in 2010 appropriate.[14]

17.3.5 LIPA's load forecasting and energy supply planning processes are appropriately integrated with the Authority's operational planning processes; as LIPA does not have a strategic enterprise planning process, energy supply planning is not integrated with enterprise risk management or strategic planning processes.

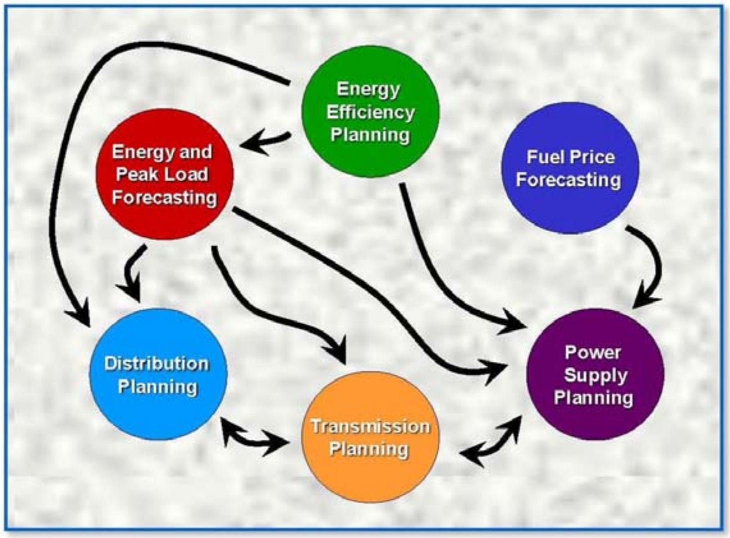
- LIPA's resource plan is based on demand forecasts that are used in system planning, revenue projections, rate design analysis, and energy efficiency program planning, and elsewhere within the Authority.[15]

- The resource plan incorporates a wide range of initiatives including energy efficiency, renewable resources and environmental responsibility, and is closely integrated with system reliability, transmission and distribution planning, and supply and system dispatch.[16]

- **Exhibit 17-5** depicts how other planning functions are included in the resource planning process.

[14] DR 300, 575 and 577
[15] DR 161 and 177
[16] DR 62

Exhibit 17-5
Interaction of Planning Processes



Source: DR 62, Appendix B

- As discussed in **Chapter 7 - Enterprise Risk Management and Strategic Planning**, LIPA does not have a strategic planning process so the energy supply process is not integrated with a formal Authority strategic plan. To a great degree, LIPA views the ERP as its strategic plan.

- LIPA and NYISO have an effective and well-defined relationship for developing both LIPA's load forecast and the state load forecast. LIPA provides its estimate of normalized peak demand to the NYISO for incorporation it the development of ICAP and related ISO documents.

17.3.6 LIPA has a well-defined midterm and long-term forecasting platform for both energy and sales forecasts that includes appropriate forecasting horizons, customer segmentation, data sources, and modeling assumptions.[17]

- LIPA's five year annual forecast of electricity sales is developed using nine econometric regression models, one for the residential sector and eight for the commercial and industrial sectors. LIPA also utilizes spreadsheet models for the following specific customers and usage types: Long Island Railroad, Brookhaven National Laboratories (BNL), Street Lighting, and Traffic Signals. The eight commercial and industrial sector models are based on North American Industrial Classification System (NAICS). The eight commercial and industrial forecasting sectors include:[18]

  - Manufacturing

[17] While National Grid personnel perform the modeling, the models are LIPA's and LIPA has the responsibility for delivering forecasts and plans to various groups, hence most of the review will refer to LIPA as the responsible party.

[18] DR 178

- Trade, Transportation and Utilities
- Leisure and Hospitality
- Financial Activities
- Information
- Business Services
- Education and Health Services
- Government[19]

- LIPA's regression models are based on the following sources of information:

  - Historical customer counts and usage per customer
  - Historical weather data from the National Weather Service – Northeast Regional Climate Center
  - Local employment, and consumer price index inflation index from the Bureau of Labor Statistics (U.S. Dept of Labor)
  - Interest rates from the Federal Reserve Bank
  - Gross Domestic Product Implicit Price Deflators from the Bureau of Economic Analysis (U.S. Dept of Commerce).
  - Electricity price forecast provided from LIPA's Rates & Pricing group.
  - Other economic drivers from Moody's Analytics including forecasts for income, mortgage rates, retail sales, gross metro product, home prices etc.

- LIPA's energy forecast is developed utilizing normal weather expressed in CDD and HDD[20] based on a thirty year average. LIPA utilizes the weather forecast for New York City from the Northeast Regional Climate Center (NRCC).[21] The NRCC collects and maintains data for 20 metropolitan areas including New York City. A thirty year average is typically seen for energy forecasts.

- LIPA's Commercial and Industrial (C&I) sector forecast is allocated to rate classes based on a historical prorated share of sales. The forecast is also converted into monthly sales for the purposes of financial modeling using historical monthly percent of sales.

17.3.7 LIPA has a load research program that provides the load factors by rate class to calculate normal weather coincident peak demand; the future of this program is unknown and other end use research is minimal.

[19] DR 396

[20] CDD = Cooling Degree Day and typically represents the number of degrees a day's average dry bulb temperature is above 65°F. LIPA uses a modified definition that includes a base of 600°F based on the temperature-humidity index (THI). THI, commonly known as heat index, includes an adjustment of dry bulb temperature for humidy. NOAA provides charts to adjust for humidity. HDD= Heating Degree Day and represents the number of degrees a day's average temperature is below 65°F.

[21] The NRCC is located in the Department of Earth and Atmospheric Sciences at Cornell University. It serves the 12-state region that includes: Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and West Virginia. NRCC maintains data for 20 metropolitan areas http://www.nrcc.cornell.edu/

- LIPA conducts load research for the major rate categories to support cost of service studies, distribution planning, choice customer settlements, rate design, and load forecasting.[22] The load research program includes the selection of a statistically relevant sample of customers where 15 minute data recorders are installed. From this data, average customer hourly load shapes and load factors are developed for each rate class.

- LIPA's Load Research program was managed by National Grid as a shared service under the MSA, with one individual dedicated to managing the program from National Grid's Syracuse, NY facility. The installation and maintenance on the meters involved in the program was performed by a meter group in the National Grid Long Island organization.

- The one individual dedicated to the program has left the National Grid, and it is uncertain how this program will be continued under the OSA.[23]

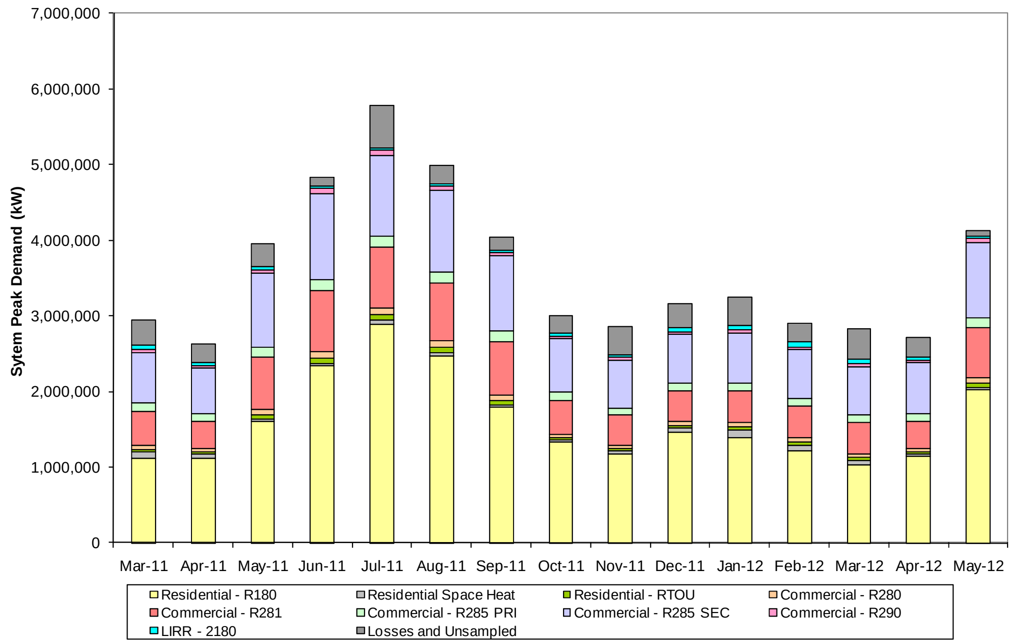
- Appliance and end use saturation surveys provide meaningful data for forecasting and development of energy efficiency programs. LIPA conducted a Residential Appliance Saturation survey in 2010, but has not updated that work. LIPA has not conducted a commercial sector appliance/end use saturation survey.[24]

17.3.8 LIPA has a well-defined platform for mid- and long-term forecasting of both normal and extreme weather coincident peak demand that includes appropriate forecasting horizons, customer segmentation, data sources, and modeling assumptions.

- LIPA's normal weather coincident peak demand forecast is based on rate class load factor at the time of the system coincident peak demand and the sales forecast.[25] The coincident peak demand for each rate class is calculated and summed for a system coincident peak demand. Typically, the peak is forecast to occur on a Summer Wednesday between 4:00 p.m. and 5:00 p.m. **Exhibit 17-6** provides the rate class contribution to coincident peak demand for each month from March 2011 through May 2012.

[22] DR 182
[23] IR 111
[24] DR 183 and DR 526
[25] Load factor is a ratio of energy consumed to peak demand. It is calculated by dividing energy by the product of 8760 hours and the annual peak demand.

Exhibit 17-6
Rate Class Contribution to Coincident Peak Demand



Source: DR 182

- LIPA's extreme weather coincident peak demand is developed through a probabilistic model.

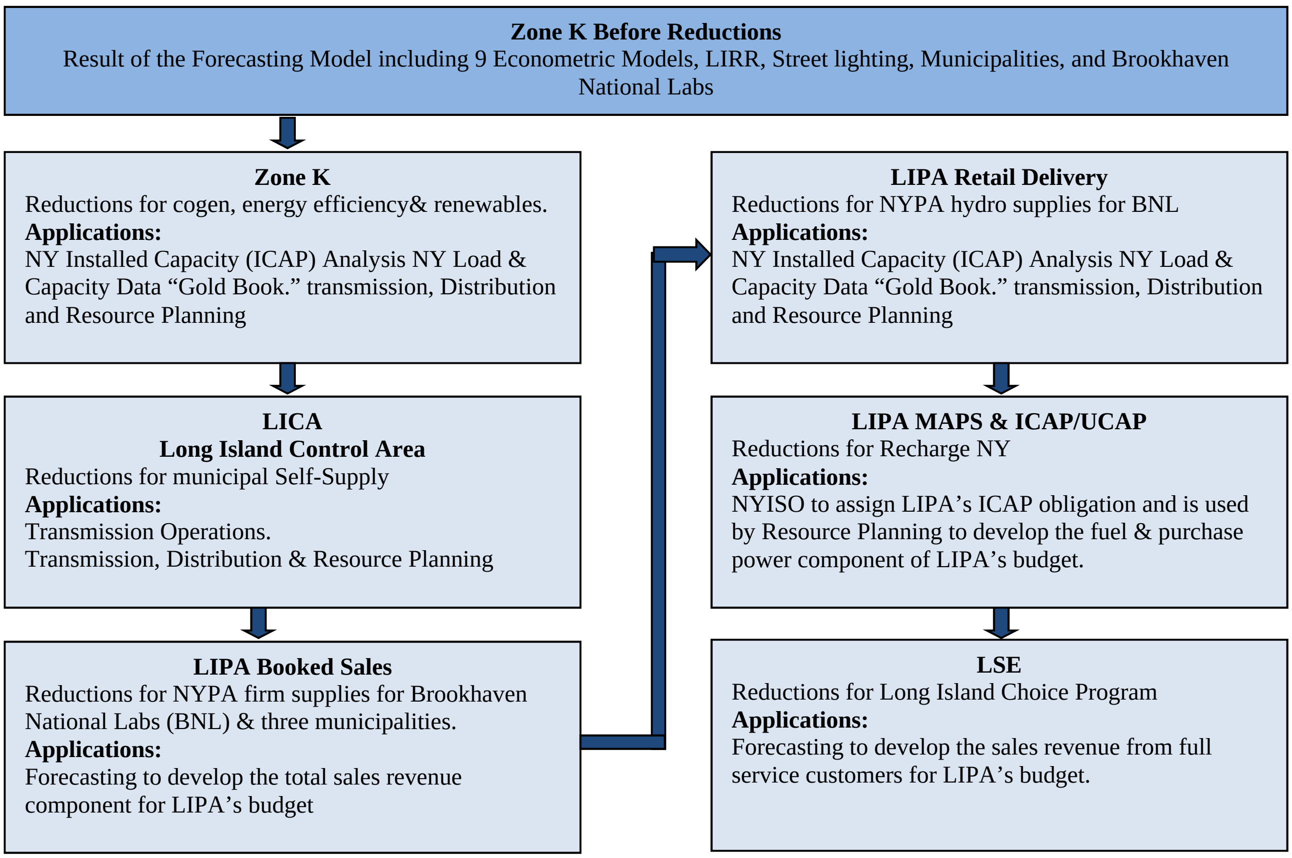
  - Utilizing the thirty most recent historical coincident peak demands and their associated temperature and humidity, a distribution is developed.
  - Peak demands are then forecast using the weather along the distribution curve.
  - Coincident peak demand is then determined for a number of probability levels across the weather distribution curve.
  - Transmission and distribution planning utilizes coincident peak demand forecasts of 50/50 and 95/5 probability levels for its Summer Operating Study. This level of confidence is necessary to insure the safe operation of the transmission system while maintaining system reliability. A detailed discussion of transmission and distribution planning is provided in **Chapter 9 – System Planning**.
  - Resource planning utilizes a 50/50 confidence level as required by the NYISO.

- LIPA's models provide a forecast of energy and demand for five years. Forecast Years 6 through 20 are developed utilizing a simple trend analysis of historical usage and Forecast Years 1 through 5.

17.3.9 LIPA utilizes appropriate post-model adjustments to its forecasts of energy and peak demand to represent the specific reliable and load area responsibilities and to meet the requirements of NYSRC and NYISO.

- LIPA applies six post model adjustments to both its energy and demand forecasts. **Exhibit 17-7** illustrates the model adjustments, and **Exhibit 17-8** provides a numerical example of the adjustments. The starting forecasts which are the output of the processes described above are labeled "Zone K Before Reductions." These forecasts represent the total electrical energy consumption potential in LIPA's service territory and the independent municipal utilities within LIPA's service area.

Exhibit 17-7
Post Model Adjustments to Load Forecast



Source: DR 796

17.3.10 LIPA's Energy Efficiency program forecasts a significant amount of load reduction by 2020; these goals represent the greatest uncertainty to the accuracy of the load forecast and subsequent resource and transmission planning products.

- In 2008, LIPA adopted its Efficiency Long Island (ELI) plan. ELI is a 10-year program that makes a wide array of incentives, rebates and initiatives available to LIPA's residential and commercial customers to assist in reducing energy usage. LIPA has also implemented programs to encourage above market appliance efficiencies and higher building standards, and to encourage small renewable energy installations. The $924 million program is funded through surcharge of approximately $0.005 per kWh assessed against all LIPA customers.[26]

Exhibit 17-8
Post Model Adjustments

Year	Zone K Before Reductions	Zone K	LICA	LIPA Booked Sales	LIPA Retail Sales	LIPA MAPS ICAP/UCAP	LSE
Sales (GWh)							
2013	22,013	21,169	21,124	20,461	20,329	20,141	18,962
2014	22,481	21,277	21,232	20,536	20,404	20,216	19,031
2015	23,022	21,465	21,421	20,712	20,581	20,393	19,200
2016	23,586	21,693	21,648	20,927	20,795	20,607	19,408
2017	23,905	21,684	21,639	20,906	20,775	20,587	19,362
Demand (MW)							
2013	5,702	5,515	5,504	5,366	5,351	5,316	5,065
2014	5,825	5,535	5,525	5,378	5,363	5,328	5,070
2015	5,966	5,587	5,577	5,428	5,413	5,378	5,114
2016	6,096	5,631	5,621	5,470	5,455	5,420	5,149
2017	6,195	5,642	5,632	5,479	5,464	5,429	5,158

Source: DR 300

- These efficiency and renewables initiatives are ambitious programs[27] and the Authority has committed significant funding and resources to their implementation, with adequate funding and a well-developed marketing plan. The ELI program is directed by nine FTE's at LIPA and implemented by 55 FTEs in National Grid Shared Services (not part of National Grid's Long Island personnel). The actual installations are performed by independent contractors. LIPA has retained an energy efficiency program development expert and a firm to conduct measurement and validation.

- LIPA's long term load forecast identifies 713 MW of coincident peak demand savings in 2020 due to energy efficiency and renewable resources, appliance standards and building codes. This represents an eleven percent reduction from peak demand that would be seen without the programs.[28] Should the goals not be achieved there would be impacts on future capacity requirements.

- LIPA reports that it has achieved between 73 and 106 percent of its energy efficiency and renewable MW goals (See **Exhibit 7-9)**.

[26] http://www.lipower.org/eli/
[27] http://www.lipower.org/newscenter/pr/2008/050808_eli.html
[28] DR 300

Exhibit 17–9
Energy Efficiency Program Success
(Measured as a percent of MW goals)

Year	**Energy Efficiency** (Percent)	**Renewables** (Percent)
2011	86	106
2012	94	73

Source: DR 239

- LIPA verifies that contractors have performed the required installations and that the quantity of (for example) appliances and bulbs have been sold. LIPA has not conducted an assessment of the actual utilization of the appliances or whether the individually purchased energy saving devices were installed in order to adjust theoretical energy or demand savings to actual savings achieved, or otherwise verified appropriate and ongoing use of the efficiency measures.[29]
- Success of any energy efficiency this program is ultimately dependent on consumer acceptance and actual use of the measurers. LIPA has not identified ultimate market penetration for the efficiency measures, which limits the number of installations and therefore amount of savings. [30]

17.3.11 LIPA's mid-term forecasting provides accurate results.

- LIPA's sales forecast of total retail sales is typically within two percent of the actual total sales for the first year of the forecast as shown in **Exhibit 17-10**. The largest degree of uncertainty is seen in the 2008 forecast. The magnitude and duration of the economic downturn and timing of the recovery was not forecast in the economic drivers.

- LIPA's sales forecast for residential sales are accurate. **Exhibit 17-11** provides the model's performance from 2007 through 2012 for residential sales.

- LIPA's sales forecast for commercial and industrial sales are accurate in the short term. **Exhibit 17-12** provides details of the model's performance for the C&I sectors in total.

[29] DR 239 and DR 530
[30] DR 239

Exhibit 17-10
Total Retail Sales versus Forecast Comparison

Year	2007	2008	2009	2010	2011	2012
Weather Normalized Sales (GWh)	**20,182**	**20,135**	**19,736**	**19,886**	**20,147**	**20,297**
2007 Forecast (GWh)	20,131	20,375	20,584	20,858	21,141	
Variance from Actual (Percent)	0.3	1.2	4.3	4.9	4.9	
2008 Forecast (GWh)		20,444	20,618	20,860	21,144	21,454
Variance from Actual (Percent)		1.5	4.5	4.9	5.0	5.7
2009 Forecast (GWh)			20,107	20,059	20,111	20,249
Variance from Actual (Percent)			1.9	0.9	0.2	0.2
2010 Forecast (GWh)				19,757	19,821	19,901
Variance from Actual (Percent)				0.7	1.6	2.0
2011 Forecast (GWh)					19,832	19,897
Variance from Actual (Percent)					1.6	2.0
2012 Forecast (GWh)						20,614
Variance from Actual (Percent)						1.6

Source: DR 392

Exhibit 17-11
Residential Sales versus Forecast Comparison

Year	2007	2008	2009	2010	2011	2012
Weather Normalized Sales (GWh)	**9,553**	**9,673**	**9,534**	**9,638**	**9,755**	**9,904**
2007 Forecast (GWh)	9,548	9,654	9,749	9,859	10,009	
Variance from Actual (Percent)	0.1	0.2	2.3	2.3	2.6	
2008 Forecast (GWh)		9,750	9,790	9,854	9,949	10,080
Variance from Actual (Percent)		0.8	2.7	2.2	2.0	1.8
2009 Forecast (GWh)			9,677	9,731	9,762	9,831
Variance from Actual (Percent)			1.5	1.0	0.1	0.7
2010 Forecast (GWh)				9,469	9,472	9,455
Variance from Actual (Percent)				1.8	2.9	4.5
2011 Forecast (GWh)					9,442	9,390
Variance from Actual (Percent)					3.2	5.2
2012 Forecast (GWh)						9,972
Variance from Actual (Percent)						0.7

Source: DR 392

Exhibit 17-12
Commercial and Industrial Sales versus Forecast Comparison

Year	2007	2008	2009	2010	2011	2012
Weather Normalized Sales (GWh)	**10,177**	**9,998**	**9,742**	**9,795**	**9,810**	**9,841**
2007 Forecast (GWh)	10,078	10,215	10,328	10,492	10,625	
Variance from Actual (Percent)	1.0	2.2	6.0	7.1	8.3	
2008 Forecast (GWh)		10,180	10,313	10,492	10,678	10,855
Variance from Actual (Percent)		1.8	5.9	7.1	8.8	10.3
2009 Forecast (GWh)			9,923	9,814	9,830	9,885
Variance from Actual (Percent)			1.9	0.2	0.2	0.4
2010 Forecast (GWh)				9,767	9,824	9,917
Variance from Actual (Percent)				0.3	0.1	0.8
2011 Forecast (GWh)					9,877	9,990
Variance from Actual (Percent)					0.7	1.5
2012 Forecast (GWh)						10,026
Variance from Actual (Percent)						1.9

Source: DR 392

- Both the Residential and C&I forecasts are driven in large part by economic drivers. During 2007 and 2008, the ultimate depth of the economic recession and timing of the subsequent economic recovery were unpredictable, causing greater uncertainty in any forecasting process. This variance is seen in the 2008 Forecasts.

- Regression results for two sectors, Manufacturing and Government, produce adjusted R-Squared values below 80 percent.[31]

  - However, the impact of these models on the total forecast in minimal. The Manufacturing and Government sectors represent approximately 11 percent of Commercial and Industrial Sales.[32]
  - The sectors are a "collection bin" of a variety of customer types.
    - Manufacturing represents both durable and non-durable industries, possibly with different economic dependencies.
    - Government represents an assortment of facilities from office buildings, to military bases, to public schools.
  - The Manufacturing and Government sectors may have too much variety in the types of customers to be considered one sector.

17.3.12 LIPA's forecast for normal weather coincident peak demand is accurate.

- **Exhibit 17-13** provides details of the model's performance. By comparing forecasted normal weather coincident peak and against weather normalized actual peak demands, the long-term performance of the model can be assessed and add confidence to the predictive capability of the extreme weather coincident peak

[31] R-Squared is a statistical measure of how well a regression line approximates real data points; an R-Squared of 1.0 (100%) indicates a perfect fit.
[32] DR 397

demand forecast. National Grid also utilized normal peak demand in its filings for the NYISO ICAP and as one case in its T&D summer operating study.

Exhibit 17-13
System Coincident Peak Demand versus Forecast Comparison

Year	2007	2008	2009	2010	2011	2012
Weather Normalized Demand (MW)	**5,239**	**5,284**	**5,208**	**5,303**	**5,269**	**5,341**
2007 Forecast (MW)	5,285	5,325	5,395	5,475	5,555	
Variance from Actual (Percent)	0.9	0.8	3.6	3.2	5.4	
2008 Forecast (MW)		5,292	5,348	5,411	5,477	5,555
Variance from Actual (Percent)		0.2	2.7	2.0	3.9	4.0
2009 Forecast (MW)			5,313	5,315	5,334	5,398
Variance from Actual (Percent)			2.0	0.2	1.2	1.1
2010 Forecast (MW)				5,202	5,225	5,247
Variance from Actual (Percent)				1.9	0.8	1.8
2011 Forecast (MW)					5,320	5,345
Variance from Actual (Percent)					1.0	0.1
2012 Forecast (MW)						5,398
Variance from Actual (Percent)						1.1

Source: DR 392

17.3.13 Resource planning at LIPA is guided through the Resource Planning Coordinating Committee (RPCC). This committee is directed by the LIPA AVP of Planning & Analysis and includes both LIPA and National Grid personnel. The group has met weekly since 2001.[33]

- The group is forum for open discussion on current Resource Planning activities, including studies, RFP evaluations, research etc.

- NorthStar attended the RPCC meeting on May 22, 2013 and observed the following:

  - The group maintains a formal agenda.
  - The group utilizes visual aids (very large screen with computer projector). All members of the group are tied into a network with access to the screen.
  - Work tasks, analyses, and investigations are assigned and included on the agenda.
  - Individuals report on work tasks, analyses, and investigations during the meetings.

17.3.14 LIPA appropriately incorporates uncertainty and reliability requirements in its resource planning process and decisions.

- LIPA uses the NYSRC IRM and the NYISO LCR requirements, plus an additional LIPA-established criteria to evaluate the reliability of alternative capacity plans.

[33] DR 227 and additional input form LIPA during fact verification regarding the duration of the RPCC.

- **NYSRC Total Statewide Reserve Margin Requirements for LIPA** – This measures whether LIPA has a surplus or a deficit against the projected statewide IRM requirement. To prevent over-procurement of future resources, LIPA targets keeping long-term commitments at or below each year's designated percent IRM measured with a 50 percent confidence level. (The IRM is revised annually by the NYSRC and is currently 17.1 percent.)
- **NYISO Zone K Locational Requirements for Long Island** – This measures whether Long Island has surplus or deficit against each year's designated Zone K LCR with a 50/50 confidence interval.[34] (The LRC is set annually and is now 105 percent of forecast peak load.) NYISO requires that LIPA meet the capacity requirements for Long Island with Long Island Resources (locational resources). These include all physical units located on Long Island and controllable DC interties with Long Island backed by firm capacity contracts.
- **Additional LIPA Planning Criteria** – LIPA has evaluated its resource plan based on the NYISO Zone K LCR at an 80 percent probabilistic confidence level – a higher confidence than the NYISO's 50/50 level.

- The three projected peak demand standards are developed from the load forecast, as described below. See **Exhibit 17-14** for a numerical and graphical comparison of the various peak load projections.

  - The Reference Load Forecast used for resource planning includes a 20 year peak demand forecast for Zone K. The forecast is based on normal weather, normal economics and normal forecast uncertainty (discussed above), and includes the forecast savings associated with the Energy Efficiency program achievements. This forecast is the reference case input to Resource Planning and has a 50/50 probability. The 50/50 probability level indicates that there is a 50 percent chance that the peak demand will be higher or lower than the forecast.
  - The Reference Zone K Load Forecast is adjusted for the mandated reserve margin and yields the NYISO Locational Requirement Load Forecast (third column of **Exhibit 17-14).**
  - The NYSRC Reserve Margin forecast is also developed from the Reference Zone K forecast. This forecast is prepared for LIPA's share of the state peak demand at the time of the State's coincident peak demand. The forecast is also adjusted for the NYSRC reserve margin (fourth column of **Exhibit 17-14).**
  - The fifth column of **Exhibit 17-14** shows the LIPA planning standard, which uses an 80/20 probability, indicating that there is an 80 percent chance that Long Island's resources will be able to meet the LCR and only a 20 percent chance that the resources will be unable to meet the LCR peak demand will be less than the forecast, and only a 20 percent chance that the peak demand will exceed the forecast.

- The use of three reliability standards assures that LIPA's long range energy supply plans will meet the requirements of the regional power markets and coordinating

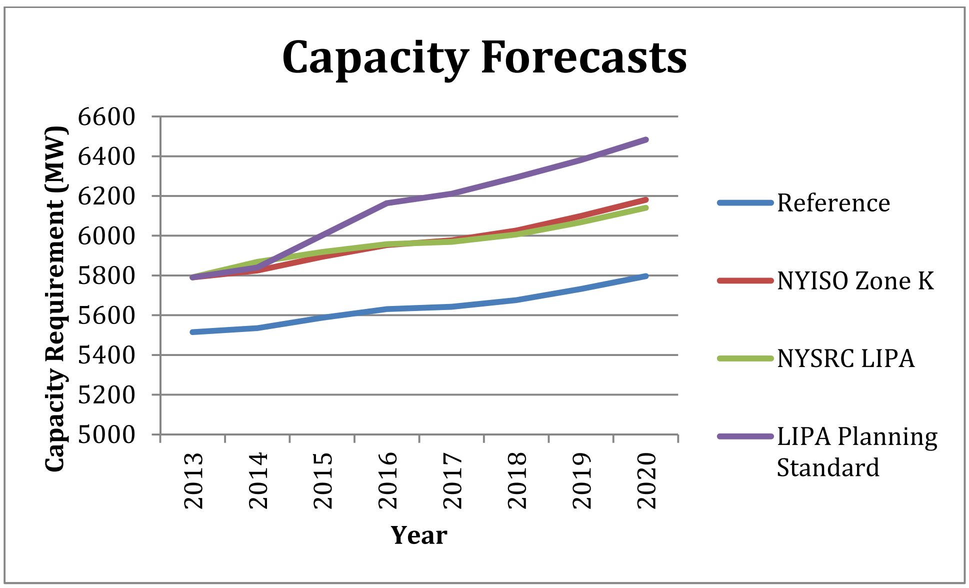
[34] DR 38

bodies. LIPA's Planning Standard is more stringent than either of the mandated criteria.

Exhibit 17-14
2012 Resource Needs Forecast
(MW)

Year	Reference Zone K Load Forecast	NYISO Zone K Locational Requirement	NYSRC LIPA Capacity Requirement	LIPA Planning Standard (RNA)
2013	5,515	5,790	5,791	5,790
2014	5,535	5,825	5,868	5,840
2015	5,587	5,894	5,918	6,002
2016	5,631	5,953	5,958	6,164
2017	5,642	5,977	5,969	6,211
2018	5,676	6,026	6,006	6,293
2019	5,732	6,099	6,068	6,381
2020	5,797	6,181	6,140	6,483

Source: DRs 300 and 575



17.3.15 LIPA uses a probabilistic approach to identify system needs, which is an improvement on traditional needs assessment methodologies.

- Traditionally, a utility's load forecasting group would prepare a normal weather, normal economics, and normal energy efficiency load forecast. Twenty-seven separate forecasts would be developed based on the high, low, and normal cases for each of the three variables. The resource planner would then have to select which of the 27 forecasts to use as the reference case for planning purposes.

- National Grid's Resource Planning group developed an in-house probabilistic model for LIPA using Excel @Risk. This model develops a probabilistic capacity-need forecast based on the uncertainties in the reference forecast (e.g., historical high demand forecasts, fuel prices, economic conditions, energy efficiency implementation).[35]

- The LIPA Planning Strategy utilizes the "At-Risk" 80/20 Probabilistic Needs Assessment for its Zone K locations requirements The probabilistic forecast states than there is an 80 percent confidence that locational requirements can meet system needs based on all the ranges and combinations of variables.

17.3.16 LIPA's long term supply planning processes and resulting long term supply plan are appropriate, encompassing cost considerations, reliability of supply and a diversity of energy supply sources, including alternative energy resources.

- LIPA's resource requirements are projected to increase 1.5 percent per year after accounting for the forecast demand savings associated with energy efficiency.[36]

- Based on current resources and forecast needs, LIPA will require additional capacity in 2016 as shown in **Exhibit 17-15.**[37]

Exhibit 17-15
Long Island Resource Needs to 2020
(MW)

Year	Requirement [1]	Current Resources [2]	Position
2013	5,790	6,007	217
2014	5,840	6,007	167
2015	6,002	6,007	5
2016	6,164	6,007	-157
2017	6,211	6,007	-204
2018	6,293	6,007	-286
2019	6,381	6,007	-374
2020	6,483	6,007	-476

[1] Requirement based on Probabilistic Needs Assessment at 80 percent Long Island (DR 575)
[2] Based on Graph in DR 577
Source: DRs 575 and DR 62

- The current resources, totaling 6,007 MW, are made up of the resources shown in **Exhibit 17-16.** All of these units satisfy the criteria set forth by the NYISO for locational requirements.

- Once the future requirements are determined, LIPA utilizes MAPS for determining the most cost efficient energy sources.

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35 IR 92 – Model working session
36 DR 575
37 LIPA noted during fact verification that this data was relevant and timely at the time of the data request, and that since that time, LIPA's ongoing Needs Assessment has changed. Due to the higher LCR for Long Island established by the NYISO and NYSRC than was in effect when the data provided in Exhibit 17.15 was develop, LIPA will need additional capacity sooner than indicated in Exhibit 17-15

- MAPS develops hourly loads based on the reference forecast, system load shapes, and the sales forecast.

Exhibit 17-16
System Peak Available Resources

Power Supply Agreement (PSA) with National Grid (MW)		Purchased Power Agreements (Fast track units) (MW)	
E.F. Barrett 1,2	385	Calpine Bethpage	77
Northport 1,2,3,4	1,552	Equus Freeport	47
Port Jefferson 3,4	383	FPLE Bayswater	54
E.F. Barrett 1-12	290	FPLE Jamaica Bay	55
Wading River 1-3	241	Pinelawn	75
East Hampton 1	18	PPL Global Shoreham	76
Glenwood 1-3	115	PPL Edgewood - Brentwood	79
Holtsville 1-10	524	Village of Freeport	10
Northport GT-1	13	NYPA Flynn	136
Port Jefferson GT	12	Global Common Greenport	48
Shoreham 1-2	64	Caithness	326
Southampton 1	7	Glenwood	80
Southhold 1	12		
West Babylon 4	49		
East Hampton 2-4	6		
Montauk 2-4	6		
Subtotal	3677	Subtotal	1063
IPP Units		**Cable Contracts**	
Hempstead Resource Recovery	71	Cross Sound Cable	330
Huntingdon Resource Recovery	24	Neptune Cable	660
Islip Resource Recovery	9		
Trigen NDEC	46	Muni Self Supply	97.5
	164[38]	Solar	15
Total On-Island Capacity (MW)	**6007**		

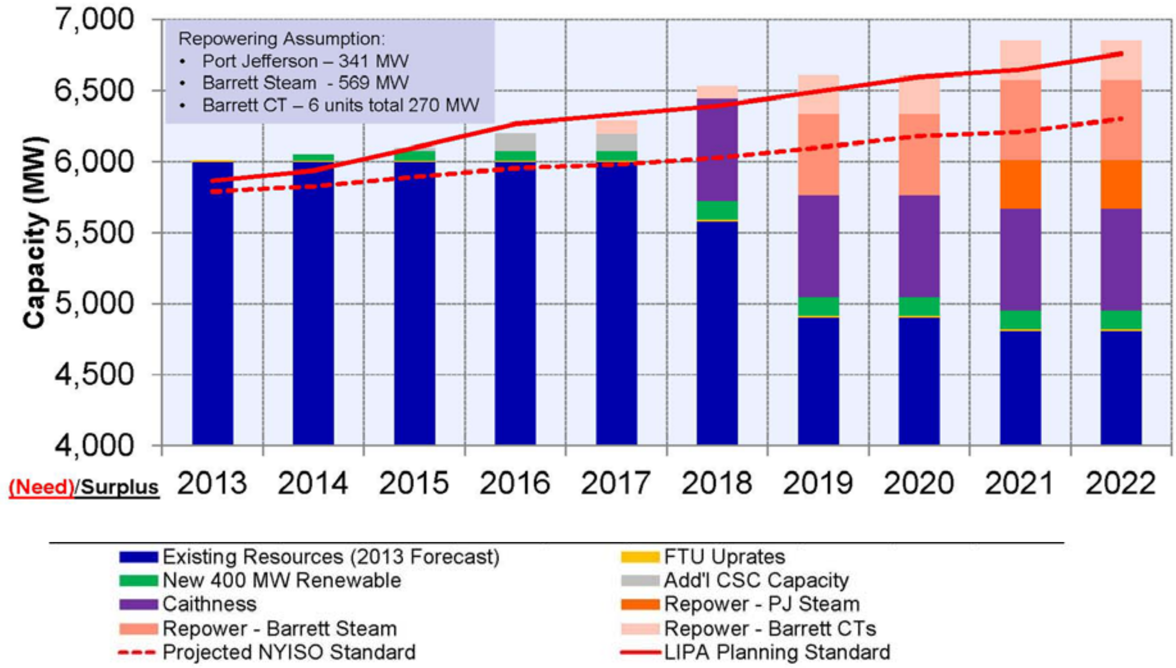
Source: DR 59 Appendix B Exhibit 3-3 and I 9

- The results from the AC Power Flow study developed in LIPA's Summer Operating Study[39] are then input into MAPS. The information is in the form of busses and loadings.
- A master input file is developed containing all available generating units, operating characteristics, fuel forecasts, emission performance, and other characteristics.
- An output file is created showing the least cost dispatch for the reference load and energy case.[40]
- Cost scenarios are identified and a least cost plan is developed based on transmission constraints, environmental sensitivity, fuel cost, and need.[41]

[38] LIPA reports a total of 164 MW in DR 62 Appendix B page 30
[39] DR 540
[40] MAPS presentation on May 23, 2010 and DR 679
[41] IR 92

- **Exhibit 17-17** provides LIPA's current projected plan for meeting its Capacity Requirements, based on the set of assumptions at the time of its development. LIPA notes that any decision would be based on economic and financial analysis of available resources obtained through competitive solicitation, providing the "best value' to LIPA customers at the time the decision was made.[42]

Exhibit 17-17
Capacity Plan



Source: DR 577

- **Exhibit 17-17** reflects the following possible changes in LIPA's supply resources:

  - Decommission the Port Jefferson Generating Station and begin construction of a new Port Jefferson Generating Station. The new unit will be online in 2021.
  - Decommission the old Barrett Steam and old Barrett CT Generating Units replacing them with new generating units, repowered Barrett Steam and repowered Barrett CT. National Grid refers to this process as "virtual repowering" in that the new units are constructed on the same site as the old units.[43]
  - 400 MW of New Renewable Resources.
  - Approximately 716 MW from the New Caithness Generating Unit
  - Approximately 230 MW of new firm capacity from the Cross Sound Cables.

[42] Fact verification
[43] DR 577, Graph

17.3.17 The planned role for on-island generation provided by the PSA and PPA units is necessary and effective; the role of the electric capacity markets is appropriate.

- The NYISO requires that LIPA comply with on-island generation requirements for reliability purposes, as discussed earlier. LIPA energy supply planning process meets the NYISO requirement to a higher degree of confidence with dedicate on-island resources, both PSA units and PPA generators. LIPA's energy supply planning does not rely on the electric capacity markets to meet its reliability planning criteria.

- LIPA conducts a robust analysis of the PSA generators, including evaluations of retirements and repowering as part of the Authorities energy supply planning process.

- As part of its resource planning program and evaluation and as part of the PSA contract renewal, LIPA evaluated its current fleet of generating resources. As a result of its evaluation its PSA resources,

  - LIPA retired the Far Rockaway 4 and Glenwood 4 and 5 generating units in June 2012. These plants were built beginning in 1930.
  - LIPA is investigating the economics of repowering its Barrett and Port Jefferson Units.

- LIPA's performed a well-grounded, sound analysis to make its recent repowering decision, as illustrated in **Exhibit 17-18.**

- Under the revised PSA contract, LIPA retains the right to modify its intended use of other PSA units.[44] Analysis of the PSA units is performed on a periodic basis as part of the Authorities on-going power supply planning and evaluation processes.

17.3.18 LIPA has an effective process for procurement of new supply resources which is applied consistently throughout the procurement process.

- LIPA issued an RFP in August of 2010 for the addition of 1,000 to 2,500 MW of new generating capacity. LIPA's evaluation of the RFP responses provides an example of LIPA's methodology in determining which proposals would be most effective and efficient.

[44] Discussed in Chapter 18 - Power Supply and Fuel Management.

Exhibit 17-18
Illustrative Repowering Justification Analysis

Repowering Project Comparison

Category	Barrett Steam	Barrett CT	Barrett/Far Rockaway Combo	Far Rockaway F Frame	Far Rockaway LMS100	Shoreham 250	Shoreham 500	Wading River
Engineering	• Highest efficiency gain. • Retire old steam unit.	• High efficiency gain. • Retires 8 CTs	• High efficiency gain. • Highest emission reduction • Creates space at Far Rockaway	• Gain in efficiency • Modest emission reduction	• No gain in capacity • Modest efficiency gain. • Less efficient • Retires Unit 4	• Modest emission reduction • Gas transportation uncertainty (Islander East) • High gain in efficiency		• Least efficient • Existing units out of service during repowering
Environmental	• Wetland impact can be mitigated		• Wetland impact can be mitigated • Community acceptance unlikely	• FAA stack height limitation. • Wetland impact cannot be mitigated	• CO emission rate may not be permittable	• Community acceptance with minor issues • 2nd easiest to permit		• Easiest to permit
Avg. Annual Emission Reductions	SO_2: 5.3% CO_2: 3.0% NO_x:16.0%	SO_2: 2.2% CO_2: 3.1% NO_x:14.7%	SO_2: 1.2% CO_2: 3.2% NO_x: 13.1%	Not analyzed	SO_2: 0.3% CO_2: 1.0% NO_x: 4.1%	SO_2: 2.9% CO_2: -0.6% NO_x: 2.6%	SO_2: 4.5% CO_2:-0.5% NO_x: 3.0%	SO_2: 9.2% CO_2: 0.2% NO_x: 6.9%
Avg. Incremental Rate Impact (2009 – 2029)	(0.05) ¢/kWh	(0.07) ¢/kWh	(0.08) ¢/kWh	Not analyzed	+0.02 ¢/kWh	+0.06 ¢/kWh	+0.01 ¢/kWh	+0.08 ¢/kWh
Energy Diversity[1] • Oil • Gas	Oil (0.8%) Gas 1.7%	Oil (0.5%) Gas 1.0%	Oil (0.3%) Gas 0.6%	Not analyzed	Oil (0.1%) Gas 0.2%	Oil (0.3%) Gas 1.3%	Oil (0.5%) Gas 1.5%	Oil (1.3%) Gas 2.8%
Savings (Millions - NPV – 2009 dollars)	$100	142	$163	Not analyzed	-$63	-$148	-$49	-$242

Notes:

[1] Increased dependence on natural gas reduces LIPA's fuel diversity.

Green — Project is strong in the area.

Yellow — Project has some issues in the area, but that the issues are manageable or of limited concern.

Red — Project has a serious issue in the area that may be difficult to manage.

Source: DR 62 Appendix E-2d

- LIPA received 45 proposals from 16 firms. This was more than the Authority had been expecting, however, the evaluation process was appropriately robust to handle the higher than expected responses, other than requiring additional time to conduct the various evaluations.

- The responses were evaluated in four phases. As each phase was concluded, the number of participants was reduced.

  - **Phase I** – Categorize, Summarize, and Check Proposal Contents against RFP Requirements
  - **Phase II – Initial Qualitative & Quantitative Evaluation:** includes calculation of an estimate of a Levelized Cost for each proposal, and takes into consideration factors including, but not limited to:
    - PPA charges;
    - technology types
    - costs incurred or reimbursed by LIPA for required transmission reinforcements; and
    - costs incurred by LIPA for gas supply and transportation, including interconnection costs and facility upgrades.
  - **Phase III – Individual Project Selection Based on Detailed Qualitative & Quantitative Evaluation**: During this phase, LIPA continues its analysis of independent projects to determine a comprehensive (All-in) cost comparison. LIPA submits additional questions to the remaining bidders and receives more detailed operating information.
  - **Phase IV – Portfolio Selection:** During this phase, LIPA analyzes groups of projects as a portfolio to determine the overall best value to the system. [45]

- LIPA selected more finalists than necessary to allow flexibility in contract negotiations. LIPA began contract negotiations with two firms in October 2012.[46]

- LIPA prepares detailed specifications of the needs and minimum parameters for the new resources, and develop in detail and specificity the bid evaluation process before the RFP is released. This assures that all responses are treated the same, and that the evaluation process is not modified based on any characteristic of the responses.

- At each step in the process, LIPA prepares extensive analyses and maintains appropriate documentation of the screening processes and resulting decisions.

- In the procurement screening process, LIPA uses the National Grid modeling resources that are used in the resource planning process. This assures that the projects are evaluated on the same basis as was used to determine need and appropriately tests the "fit" of proposed projects with the rest of the LIPA system. [47]

[45] DR 817
[46] http://www.lipower.org/pdfs/company/papers/board/102512-generation.pdf
[47] DR 302, DR 579 and DR 817

17.4 Recommendations:

17.4.1 Contract for an independent evaluation of the actual effectiveness and achievements of the current energy efficiency initiatives and programs, including verification of energy and capacity savings actually achieved in field installations, and assess the reasonableness of future ELI goals given current market penetration and overall market trends

17.4.2 Prepare, or cause PSEG-LI to prepare, a new or updated ERP that addresses the entire resource plan needed to meet future energy supply needs for Long Island, including realistic, economic assessments of traditional generation, innovative commitment opportunities, renewable resources, and the results of the energy efficiency evaluation, while recognizing the need for flexibility to respond to and take advantage of opportunities and changing market and technological conditions. This plan should be available to the public and provide a general guideline for resource decisions and a benchmark against which to measure achievements and progress towards all of the planning goals.

17.4.3 Provide periodic (annual) updates to the BOT, in conjunction with PSEG-LI, on progress towards and changes in the energy resource plan, including status reports on progress towards efficiency, renewables and GHG goals.

17.4.4 Assess the value of continuing LIPA's Load Research program, and investigate the potential value to forecasting and energy efficiency program development of periodic residential and commercial appliance saturation and end use surveys.

17.4.5 Maintain, to the extent possible, the current energy supply planning processes, resources, organization, and tools under the ServCo model. Changes to the planning process should demonstrate a strong likelihood of significant improvement in efficiency or results.

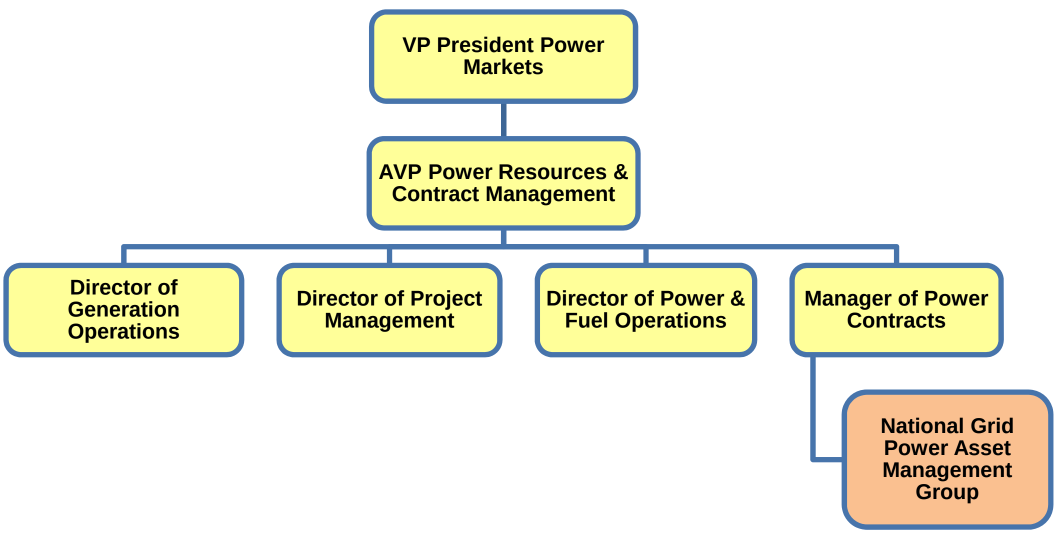
18. Power Supply and Fuel Management

This chapter focuses on LIPA's management of its long-term power and fuel supply contracts, its day-to-day wholesale energy market activities, and its energy risk management.

18.1 Background

LIPA's Power Resources and Contract Management group, which is part of the Power Market group, is responsible for the oversight of LIPA's power and fuel supply contracts, daily power supply management, and participates in energy risk management activities. The organization of this group and its interfaces with National Grid are shown in **Exhibit 18-1.**

Exhibit 18-1
LIPA's Power Resources and Contract Management Group



- LIPA's Assistant Vice President (AVP) of Power Resources and Contract Management oversees all of the activities carried out by the Directors and Managers in his organization, including the administration of LIPA's long-term power supply, transmission and related contracts, monitoring compliance with terms and conditions of contracts, assuring accurate and timely payments, and overseeing the various functions performed by National Grid and other contractors on LIPA's behalf.

- The LIPA Director of Generation Operations is responsible for the operations and performance of all the power plants under contract to LIPA, including review of plant availability and efficiency; operations and maintenance scheduling and costs; performance monitoring and evaluation; assessment of capital improvements and environmental performance; and support of contract compliance reviews.[1] In

[1] DR 344

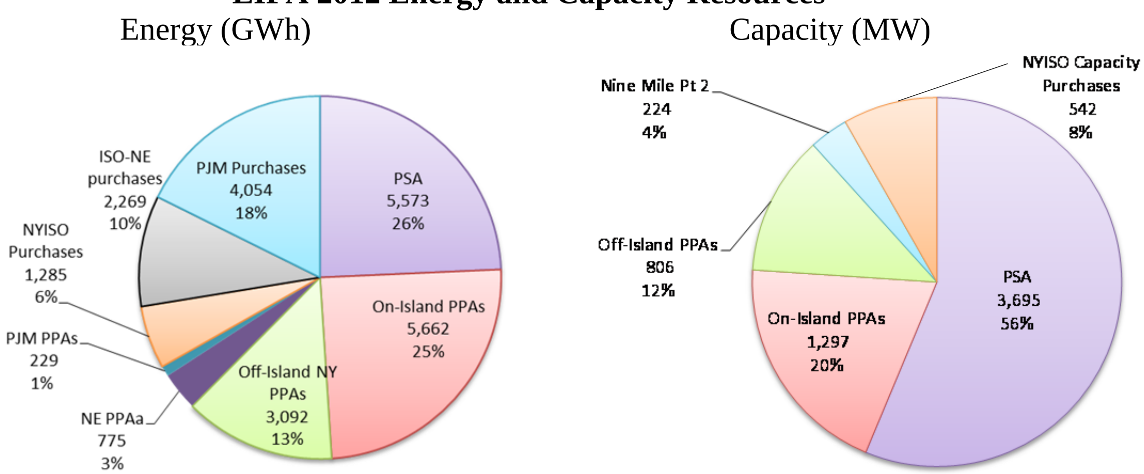
addition, as administrator for the Power Supply Agreement (PSA), he reviews PSA invoices and proposed plant betterment projects[2]

- The Manager of Power Contracts is responsible for negotiating contracts for the long-term purchase of electric capacity, energy, ancillary services, and renewable energy and credits.[3] He is also responsible for oversight of power purchase agreements (PPAs) in addition to the PSA and oversees the contract administration functions performed by National Grid's Power Asset Management (PAM) group.[4]

- The Director of Fuel and Power Operations manages and monitors the day-to-day operations of CEE and Pace under the Power Supply Management (PSM) and the Power Supply Management Middle Office (PSMMO) contracts, respectively. He also oversees and monitors physical fuel purchases, deliveries, and operations, as well as associated protocols, procedures, and strategies to deliver oil products and natural gas to the PSA units and PPA units for which LIPA is responsible for fuel supply. He also assists with LIPA's energy price hedging program, as discussed further below.

- The Director of Project Management is responsible for coordinating and managing LIPA's involvement in developing major generation, transmission and interconnection projects owned by or under contract to LIPA, and reports to the Power Markets group. **Exhibit 18-2** shows LIPA's 2012 capacity and energy mix.

Exhibit 18-2
LIPA 2012 Energy and Capacity Resources



Source: DR 785
Note: In addition to the resources shown above, LIPA reported that it received 1,142 GWh energy and 86 MW capacity from LIPA's energy efficiency programs and 56 GWh energy and 7 MW capacity from LIPA's renewable energy programs.

[2] IS 138
[3] DR 344
[4] IS 138

Almost all of LIPA's power supply is under long-term contracts with varying expiration dates ranging from 2014 to 2034. The majority of LIPA's annual power supply (capacity) is linked to the following long-term contracts:[5]

- **Power Supply Agreement (PSA)** — Provides for the sale to LIPA by National Grid Generation (National Grid-Genco) of all of the capacity and, to the extent LIPA requests, energy from the former LILCO oil and gas-fired generating plants on Long Island (the PSA units). The PSA provides about 60 percent of LIPA's capacity and 26 percent of its annual energy requirement.

- **Caithness** — A 326-megawatt combined cycle plant on Long Island that has provided about 10 percent of LIPA's annual energy requirement since 2009.

- **Neptune Regional Transmission System** — A 660 MW HVDC (High Voltage Direct Current) submarine cable to New Jersey that enables LIPA to obtain about 10 percent of LIPA's capacity and about 20 percent of its annual energy requirement from the typically lower-cost PJM market. A long-term resource, Marcus Hook (685 MW), is linked to this contract to provide capacity only. The Neptune cable began commercial operation in the summer of 2007.[6]

- **Cross Sound Cable (CSC)** — A 330 MW HVDC submarine cable to New England that enables LIPA to obtain capacity and energy in the New England market when it is cost effective to do so.[7] A 100 MW pumped storage facility, Bear Swamp, is linked to the CSC contract. The Cross Sound Cable began commercial operation in 2002.[8]

LIPA generation is dispatched and purchases are made on an economic basis with some "out of merit" generation dispatched to meet local reliability issues when necessary. The CSC and Neptune cables enable LIPA to source considerable energy in New England and PJM, respectively, as shown in **Exhibit 18-2**, above.

Under the PSA, originally signed in 1998, National Grid-Genco provides approximately 3,600 MW of capacity to LIPA from the oil and gas-fired generating plants on Long Island which were formerly owned by LILCO.[9] The units covered by the PSA are shown in **Exhibit 18-3**. The PSA sets forth the terms and conditions for the sale and delivery of electric capacity, energy conversion and ancillary services by National Grid to LIPA.

The PSA is subject to Federal Energy Regulatory Commission (FERC) cost-of-service regulation and is a tolling agreement under which LIPA provides all fuel for the units, is entitled to all electric output from them, and is solely responsible for the dispatch and for bidding those units into the NYISO capacity and energy markets. Under terms of the PSA, the PSA units only run when requested by LIPA. While LIPA is not obligated to purchase

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[5] DR 246 NYPA LIPA Contract Review
[6] LIPA Electric Resource Plan 2010 – 2020, Appendix C, Energy Primer
[7] DR 246 NYPA LIPA Contract Review CONFIDENTIAL
[8] LIPA Electric Resource Plan 2010 – 2020, Appendix C, Energy Primer
[9] LIPA Electric Resource Plan 2010 – 2020.

energy or ancillary services under the PSA, the Authority is required to purchase the PSA capacity.[10]

Exhibit 18-3
PSA Unit Characteristics

PSA Units:	Capacity (MW)	Facility Type	Fuel
E.F. Barrett 1,2	385	ST	Gas, Residual Oil
Far Rockaway 4 [1]	111	ST	Gas
Glenwood 4,5 [1]	239	ST	Gas
Northport 1,2,3,4	1,552	ST	Gas, Residual Oil
Port Jefferson 3,4	383	ST	Gas, Residual Oil
E.F. Barrett 1 12	305	CT	Gas, Distillate
Wading River 1 3	241	CT	Distillate Oil
East Hampton 1	18	CT	Distillate Oil
Glenwood 1 3	115	CT	Distillate Oil
Holtsville 1 10	524	CT	Distillate Oil
Northport GT 1	13	CT	Distillate Oil
Port Jefferson GT	12	CT	Distillate Oil
Shoreham 1,2	64	CT	Distillate Oil
Southampton 1	7	CT	Distillate Oil
Southhold 1	12	CT	Distillate Oil
West Babylon 4	49	CT	Distillate Oil
East Hampton 2	6	IC	Distillate Oil
Montauk 2	6	IC	Distillate Oil

Source: LIPA 2011 Annual report
[1] LIPA removed Far Rockaway and Glenwood Steam from the PSA in June 2012

The original PSA expired by its terms on May 27, 2013; the “Amended and Restated” PSA (A&R PSA) began on May 28, 2013 and ends April 30, 2028. The A&R PSA permits LIPA to continue to purchase capacity, energy and ancillary services from National Grid pursuant to essentially the same tolling arrangement as the 1998 PSA at cost-based formula rates.

The PSA provides incentives and penalties for National Grid-Genco to maintain the output capability of the generating facilities as measured by annual industry-standard tests of operating capability, and to make capital improvements that benefit plant availability. Under terms of the original PSA, National Grid -Genco would receive incentive payments upon meeting performance targets; under the A&R PSA, National Grid -Genco receives penalties if performance targets are not met.[11]

In addition to the PSA, LIPA purchases approximately 2,100 MW of capacity under long term PPAs as listed in **Exhibit 18-4.**[12]

[10] FERC ORDER ACCEPTING AND SUSPENDING PROPOSED TARIFF SHEETS, AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES, Issued March 31, 2010, Docket ER10-705-000
[11] DR 258
[12] Fuels Services RFP

Exhibit 18-4
Summary of Purchased Power Agreements (Excluding the PSA)

Plant	Capacity (MW)	Contract Start	Contract End	Unit Type	Primary Fuel Type
On-Island (LIPA has fuel responsibility)					
Edgewood Energy	86.6	2002	2018	SC	Natural Gas
Global Common Greenport	52.0	2003	2018	SC	Kerosene
Genco Glenwood Landing	79.9	2002	2027	SC	Natural Gas
Genco Port Jefferson	82.3	2002	2027	SC	Natural Gas
NextEra Bayswater	53.7	2003	2020	SC	Natural Gas
NextEra Jamaica Bay	54.3	2003	2018	SC	Kerosene
Shoreham Energy	86.6	2002	2017	SC	Kerosene
Caithness [1]	309.6	2009	2029	CC	Natural Gas
NYPA Holtsville (Flynn) [2]	134.9	1994	2014	CC	Natural Gas
Calpine Bethpage 3	76.6	2005	2025	CC	Natural Gas
Equus	47.7	2004	2017	SC	Natural Gas
Pinelawn Power	74.6	2005	2025	CC	Natural Gas
Off-Island					
Bear Swamp Power	100.0	2007	2021	PS/Hydro	Water
Fitzpatrick	124.4	1975	2014	ST	Nuclear
Gilboa	50.0	1989	2015	PS	Water
Marcus Hook	685.0	2010	2030	CC	Natural Gas
Other					
Babylon Resource Recovery	14.6	1989	2017	ST	Refuse
Hempstead Resource Recovery	72.4	1989	2017	ST	Refuse
Huntington Resource Recovery	24.4	1991	2017	ST	Refuse
Islip Resource Recovery	9.2	1990	2017	ST	Refuse
Village of Freeport	10.0	2004	2034	SC	Natural Gas
Eastern Long Island Solar Project	11.3	2011	2032	PV	Solar
Long Island Solar Farm	31.5	2011	2031	PV	Solar
PPL Energy Plus	Energy Up to 25GWh	2009	2019	IC	Landfill/Methane
Suez Nassau Energy Comb. Cycle	43.2		2016	CC/Cogen	Natural Gas

Source: 2011 LIPA Annual Report; DR 472
Note 1 - LIPA agreement to purchase 286 MW of the total capacity
Note 2 – NYPA has fuel responsibility. LIPA has fuel responsibility for the other On-Island units.

Since 2001 LIPA has added nearly 1,800 MW of supply capability which includes contracts with 12 new on-Island generating stations and two submarine cables, Neptune and CSC, which connect Long Island to neighboring power markets. The results of LIPA's major power supply procurement efforts since 2001 are listed in **Exhibit 18-5**.

The responsibility for procurement and management of natural gas and fuel oil for the PSA units and some of the PPA units was provided by National Grid's Energy Trading Services group (NGET) from June 1997 until May 28, 2013. There are three agreements that collectively covered the fuel procurement services:

Exhibit 18-5
Major Power Supply Procurement (Since 2001)

Year	RFP	PPA
2001-2002	"Fast-Track" Units	Ten On-Island peaking projects
2002	Combined-Cycle	Bethpage and Pinelawn
2003	Base Load	Neptune Cable and Caithness
2005	Off-Island	Bear Swamp and Marcus Hook
2007	Renewable	Brookfield and PPL
2008	Solar	Long Island Solar Farm, and Eastern LI Solar

LIPA Electric Resource Plan 2010 – 2020, Appendix C, Energy Primer

- **Energy Management Agreement (EMA) -** The EMA calls for NGET to procure and manage fuel supplies (both oil and natural gas) for the PSA units.[13] The cost of delivery to the units via National Grid's Long Island gas distribution utility (KEDLI) was fixed at $0.19/dth and was added to the cost of the gas purchased. Balancing services were provided at no cost, meaning there was no penalty for imbalances between nominations and actual burn on either a plant specific or aggregate basis. Fuel and transportation invoices were paid by NGET on behalf of LIPA, with a simultaneous payment by LIPA to NGET. For its services, NGET received a monthly management fee and was eligible for an incentive or penalty based on the prices paid for the fuel compared to market price. The incentive/ disincentive payment clause was pegged to an acquired average gas price of 102 percent of the market price on a monthly basis. If the actual average price of purchased gas was less than 102 percent of the benchmark, NGET received an incentive equal to half the difference; if the actual average price of the gas was higher than 102 percent of the market price, NGET was penalized one-half of the difference

- **Fuel Management and Bidding Services Agreement (FMBSA) -** The FMBSA called for NGET to provide essentially the same fuel management services as were provided to the PSA units but for various PPAs that are under "tolling" agreements. The FMBSA did not include transportation from the city gate to the plants or balancing services (covered under the separate Transportation Agreement, discussed below). NGET was paid only a fuel management fee for its services; there was no incentive/disincentive clause in this agreement.

- **Omnibus Gas Transportation and Balancing Agreement (Transportation Agreement)** - This agreement between LIPA, NGET and KEDLI confirmed the fixed transportation rate for the PSA units, and set rates for the other tolling units. For gas deliveries to the non-PSA units, imbalances had to be cashed out -- daily for larger imbalances (outside of a +/-4% tolerance band) and monthly for the accumulation of smaller imbalances. As a result of these balancing charges, LIPA tended to set bidding specifications such that the non-PSA units would run at a high utilization rate (and therefore have stable predictable fuel requirements). The PSA units would tend

[13] Prior to 2010, NGET also provided Power Management (scheduling, bidding, buying and selling of capacity and electric energy) under the same EMA. These functions are now performed by CEE under the PSM Agreement, as described below.

to be more "swing" units with less predictable fuel needs, and with no penalty if gas usage varied from scheduled.

Effective May 28, 2013, the fuel procurement and management functions were taken over by CEE under a new Fuel Management Agreement (FMA).[14] The FMA specifies fuel management services similar to those in the EMA and includes performance penalties.[15] The Transportation Agreement expired on May 28, 2013 coincident with the expiration of the EMA. Effective May 28, 2013, the necessary gas supply transportation is provided by KEDLI under a service agreement that is subject to review by the NYPSC.[16]

The analyses of the fuel procurement functions in this Chapter are based upon NGET's performance under the EMA/FMBSA, and LIPA's oversight and management of that contractor. While the contractor providing the services has now changed, the functions that have to be performed by the fuel manager are the same, and the LIPA polices and personnel overseeing the contract remain the same as in the past. Thus, experiences and lessons learned from the NGET performance have relevance for the new contractor.

LIPA's day-to-day power supply management (PSM) functions – bidding and scheduling of all LIPA Generating Facilities and purchases and sales of energy, capacity and ancillary services – are provided by CEE and PACE. CEE provides "front" and "back" office PSM services. Front office PSM services include day-ahead load forecasting, the bidding of capacity, energy and ancillary services into respective ISO electricity markets, and the scheduling of power transactions across cables interconnecting LIPA's service area to surrounding ISO markets. Back office PSM services include the review of settlements and billings associated with market transactions. PACE provides middle office PSM services, which include monitoring the performance of CEE's PSM activities. With the transition from NGET to CEE as LIPA's fuel manager, PACE will provide middle-office oversight of CEE's fuel operations as well.[17] Services under both the CEE and PACE contracts commenced full operation on January 1, 2010 and are for an initial five-year period, subject to an extension for a period of five years at LIPA's option.[18]

A significant part of LIPA's power supply management involves interactions with the NYISO electricity markets for installed capacity, energy, and ancillary services, and the NYISO settlements and billings function. These NYISO functions are briefly described below.[19]

[14] While the FMA is a separate agreement, the fuel procurement and scheduling services will be performed by the same group within CEE.

[15] DR 870

[16] DR 903

[17] DR 164

[18] CEE performs this work per its Contract for Providing Power Supply Management Front and Back Office Services or the PSMFB contract; PACE performs its work per its Power Supply Management Middle Office Services or PSMMO contract. For this discussion we will use "PSM services" to refer to the services provided under both contracts.

[19] NYISO also operates a market for transmission congestion contracts (TCC); however, LIPA does not participate in this market beyond its existing grandfathered TCC contracts, as the market for congestion spreads that sink to Zone K is illiquid. (DR 164, PSM Front and Back Office Procedures)

- **Installed Capacity Market –** The Installed Capacity (ICAP) Market ensures that there is sufficient generation capacity to cover the capacity requirements determined by the NYISO. An ICAP resource is a generator or load facility that is accessible to the New York state transmission system, which is capable of supplying and/or reducing the demand in the NYCA and which complies with the requirements of the reliability rules. There are three types of auctions: strip (for six month period), monthly (for remaining months in strip auction period), and spot (for next month). [20]

- **Energy Market –** The energy market provides a mechanism for Market Participants to buy and sell energy and to bid various kinds of bilateral transactions. Suppliers may sell energy directly into the market or be party to a bilateral contract selling directly to purchasers. Load serving entities and others may purchase energy by submitting bids and/or they may be party to a bilateral contract purchasing directly from a supplier. The NYISO energy market uses a two-settlement process: 1) The first settlement is based upon the day-ahead bids and the corresponding schedule and prices determined by the day-ahead security constrained unit commitment, 2) The second settlement is based upon the real-time bids and the corresponding real-time commitment and real-time dispatch. [21]

- **Ancillary Services Market –** Ancillary services support the transmission of energy and reactive power from supply resources to loads and are used to maintain the operational reliability of the power system. NYISO coordinates, controls, and, if necessary, directs the actions of generation resources and other facilities that provide ancillary services to the NYISO. [22]

- **Settlements and Billing** – NYISO market settlements activities focus on the invoicing of NYISO power market products, as well as distributing data that the settlements are based on. Settlement details and associated data are provided to Market Participants through a web-based data warehouse. Market Participants are responsible for independently reviewing the data that was used to generate their settlement and billing statements to ensure that all input data was accurate and complete, and to immediately report any discrepancies to NYISO personnel.[23]

LIPA has a highly complex and actively managed energy risk management program. The program uses the concept of Value-at-Risk (VaR) to simulate and measure exposures to energy price volatility and financial hedges to constrain worst-cost outcomes with respect to fuel and purchased power, mark-to-market hedge losses, and option premiums. LIPA also manages transaction-related risks such as exposures to unsecured counterparty credit and collateral posting requirements.

LIPA's hedge strategy is to systematically execute financial hedges up to a predetermined hedge ratio over a three-year time horizon; and then as market conditions warrant, execute additional hedges or unwind hedges based on potential breaches of established risk tolerance

[20] Info taken from NYISO Participants User Guide
[21] Info taken from NYISO Participants User Guide
[22] Info taken from NYISO Participants User Guide
[23] NYISO Website

boundaries. LIPA typically deploys swaps and/or options to hedge its exposures to risk including a combination of fuel and/or basis swaps to hedge fuel, and heat-rate and fuel swaps to hedge purchased power.

PACE serves as LIPA's External Risk Advisor responsible for formulating and recommending hedge strategies and structures. PACE also monitors risk exposures and compliance with energy risk management policies and procedures.[24] LIPA's financial hedges are executed by two authorized in-house traders, one located in the financial treasury department and the other in the Power Markets group.

18.2 Evaluative Criteria

- Is the oversight of the power supply contracts assigned to appropriate LIPA personnel? Where used, does LIPA effectively use outside resources to monitor the contractors' performance on these contracts? Are the oversight responsibilities clearly delineated?
- Are LIPA's oversight and controls of its power supply contracts adequate and effective?
- Does LIPA take appropriate action when any of its power supply contractors do not meet performance standards or comply with contractual requirements? Has LIPA taken adequate corrective actions in response to any previous recommendations regarding its oversight of its power supply management contracts?
- Does LIPA audit, enforce and manage the PSA, and other power supply agreements to effectively and efficiently balance reliability with low cost electricity for its customers?
- Was the recent renegotiation of the PSA appropriate in light of the PSA units' performance and other available generation options?
- Does LIPA audit, enforce and manage its Fuel Management agreements to obtain low cost fuel supplies for the power plants where it is responsible for the fuel supply?
- Does LIPA have appropriate resources to oversee the fuel management agreements and are the oversight responsibilities clearly delineated? If not, does LIPA effectively use outside resources to monitor its contractors' performance?
- Has LIPA taken appropriate action when its fuel manager did not meet performance standards or comply with contractual requirements?
- Does the new FMA include changes to address areas of weakness in the prior fuel agreements?
- Are LIPA's oversight and controls of the power supply management contracts and the associated activities, functions, and performance adequate and effective?
- Are the types and extent of communications (both real time and regular reports) between the various contractors and LIPA with respect to the power and fuel supply contracts sufficient?
- Does LIPA audit, enforce and manage the PSM with CEE, and the Middle Office Agreement with PACE so that the use of LIPA's capacity portfolio and its capacity

[24] This is a different contract that the PACE contract for Power Supply Management Middle-Office services discussed above.

and energy market participation effectively and efficiently balance reliability with low cost electricity for its customers?

- Does LIPA set appropriate power supply delivery performance goals?
- Does LIPA have appropriate financial risk management policies, strategies and practices relative to fuel and purchased power pricing?
- Is there appropriate coordination and collaboration between financial risk management and the management of supply and supply price risks?
- Does LIPA have appropriate financial hedging practices by customer type?
- Does LIPA use supply procurement performance benchmarking with other utilities in an appropriate manner to improve and monitor procurement performance?
- Does LIPA use appropriate methods to evaluate the effectiveness of its financial risk management program with respect to price volatility and cost?

18.3 Findings and Conclusions

18.3.1 Oversight of the PSA, other power supply contracts, and the fuel supply contracts is appropriately assigned to LIPA personnel, with support from National Grid.

- LIPA's Power Resources and Contract Management group (Power Resources Group) is responsible for the oversight of LIPA's power supply contracts, with the assistance of National Grid's PAM group, as was shown in **Exhibit 18-1**

- The Manager of Power Contracts oversees the contract administration functions performed by National Grid's PAM.[25] PAM manages all interactions with developers, owners, and operators of Distributed Resource/Independent Power facilities within the LIPA service territory to ensure that LIPA's interests in matters pertaining to project development, interconnection, and operations are properly addressed at all times.[26] The group also reviews PPA invoices.

- LIPA personnel directly responsible for the oversight of the PSA and other PPAs have more than adequate experience.

  - The Director of Generation Operations, who serves as the PSA administrator and is responsible power plant operations analysis, has over 30 years power plant experience as an engineer, utility project engineer, and as a consultant to LIPA.[27]
  - The Manager of Power Contracts, who is also responsible for oversight of power purchase agreements other than the PSA, has over 30 years utility experience.[28]

18.3.2 LIPA's renegotiation of the PSA improved contract terms and conditions to provide for the continued purchase of power from National Grid-Genco at a lower cost and to provide for additional benefits not included in the Original PSA.

[25] IS 138
[26] DR 391
[27] IS 138
[28] IS 198

- LIPA and National Grid had extensive negotiations over an 18-month period to produce the A&R PSA for 3,600 MW of capacity.

  - LIPA developed an analytical model to assess the economic, financial, and rate implications of various contract options including but not limited to: (1) letting the contract expire; (2) renewing the contract under substantially similar terms and conditions, and (3) renewing the contract under a new negotiated agreement.[29]
  - LIPA assessed the contract options under various scenarios, including replacing all 3600 MW PSA capacity with other sources by 2026; and replacing 1,500 MW capacity by 2026.

- The A&R PSA reduces LIPA's costs relative to the 1998 PSA. In 2012, costs under the Original PSA were approximately $450 million annually, comprised of $270 million in payments to National Grid for operating and maintaining the generation fleet, and $180 million in property tax payments to localities related to PSA units.[30]

  - The A&R PSA has a lower capacity charge (relative to the Original PSA) which is guaranteed for the first five years, and which will result in an immediate price reduction amounting to nearly $10 million through 2017.[31]
  - The A&R PSA also provides for significantly reduced future charges through the end of the contract if LIPA exercises its rights to remove older Genco-owned generating facilities from the contract. Such benefits are estimated to range from $100 million to more than $1 billion over the term on the A&R PSA, depending on which units are ramped down.[32] The A&R PSA establishes a "Tracking Account" which would allow LIPA to retire plants initially at no charge, up to a total equal to the net book value of Northport Unit No. 1 ($70 million), so as to approximate the value LIPA could have extracted from the original PSA by ramping down that unit in 2013 As a practical matter, LIPA's need for Northport Unit No. 1 to remain in service effectively precluded LIPA's ability to exercise that ramp down option in the original PSA.[33]

- The A&R PSA establishes procedures to evaluate the feasibility of a potential repowering of the Port Jefferson, Barrett (Island Park) and Northport steam plants, as well as the Barrett and Holtsville combustion turbine sites. Any repowering of these plants would be based on the results of an economic study and subject to a mutually agreeable power purchase agreement between Genco and LIPA, a separate environmental review, and LIPA Board approval. The A&R PSA also establishes a potential phase-out schedule for any plants that cannot be repowered or that fail to continue operating economically. [34]

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[29] DR 344
[30] http://www.lipower.org/newscenter/pr/2012/100212-power.html
[31] http://www.lipower.org/newscenter/pr/2012/100212-power.html
[32] DR 880
[33] DR 880
[34] http://www.lipower.org/newscenter/pr/2012/100212-power.html

- The FERC order approving the A&R PSA points out the benefits to LIPA: "We find that this agreement not only reduces costs to LIPA as compared to the 1998 PSA, but also provides LIPA with additional flexibility to address changing conditions. This flexibility is the result of the addition of the repowering and ramp down provisions that were not present in the 1998 PSA."[35]

18.3.3 LIPA has sound processes to monitor PSA generation plant performance.

- LIPA monitors generating plant performance on a monthly, seasonal and annual basis with respect to the performance criteria established in the PSA for capacity, availability, and heat rate. The basis of the monitoring is a series of reports from National Grid; the data is validated through calculations performed by LIPA.

- National Grid issues an "Electric Generation Performance Report" for its steam units and a "Combustion Turbine Department Report" for its internal-combustion units on a monthly basis. These reports contain extensive data on the operation and performance of the PSA generating units for the respective month. [36]

  - National Grid's monthly Electric Generation Performance Report provide detailed information regarding the performance of Port Jefferson, Northport, E.F. Barrett units, and included the Far Rockaway and Glenwood units until they were removed from the PSA in June 2012. Information provided in the report includes:
    - Heat Rate performance for all plants and each individual plant
    - Heat Rate Incentive/Disincentive performance
    - Fuel Accounting
    - Detailed Plant Data
    - Generation data
    - Heat Rate Analysis and Costs
    - Forced Outage Rate
    - Monthly Trend Curves
    - DMNC testing results (Dependable Maximum Net Capability – a measurement of installed capacity value).[37]
    - Measured Installed Capacity Values
  - National Grid's monthly Combustion Turbine Department provides detailed statistics on the PSA gas turbines as well as the two PSA fast track units. Information provided in the report includes:
    - Hours, starts and generation
    - Generating Availability data
    - Fuel Accounting
    - Equivalent Forced Outage Rate – demand (EFORd)
    - DMNC history

[35] FERC Order on Tariff Docket No. ER13-1159-000
[36] DR 158
[37] DR 769

- The Director of Generation Operations reviews these reports and extracts data for trending, looking for trend changes that might reflect deterioration of a unit's condition. He also compares current-month data to historical norms, looking for deviations from norms that indicate problems that may need corrective action.[38] The reports track a few fundamental metrics, such as btu/MWh, capacity factor, and forced outage rate, which indicate whether a particular unit is performing acceptably under the PSA, or may have problems meriting closer attention.[39]

18.3.4 LIPA has a sound review and approval process for the PSA invoices.

- LIPA's Director of Generation Operations serves as PSA Administrator and reviews the capacity, variable, and carbon-dioxide-emissions-allowance invoices for correctness and conformance with the terms of the PSA, and ensures the invoices have appropriate documentation and substantiation of charges. He also performs checks and independent calculations as necessary to confirm that the amounts of invoices are appropriate. [40]

  - Monthly capacity invoices are reviewed to assure that the amount invoiced is equal to the amount established for the respective year in accordance with the terms of the PSA. National Grid annually provides LIPA a package of spreadsheets and work papers that document its calculation of the annual capacity charge for that year, which is invoiced in 12 monthly installments. [41]
  - Monthly variable invoices are reviewed to verify that they are accompanied by documentation to substantiate each line item in the invoice. [42]
  - Carbon dioxide emissions allowance invoices are submitted by National Grid on a monthly basis, to the extent that allowances that it has purchased are used to cover carbon-dioxide emissions from the PSA units. The Director of Generation Operations typically checks these invoices against his independent calculation of tons of carbon dioxide emitted based on the quantity of fuel burned during the period covered by the invoice. [43]

- Upon being satisfied that invoices are correct and appropriate, the Director initials and forwards them to the Assistant Vice President of Power Resources and Contract Management. If he is satisfied with the Director's review, he initials the invoices, after which they are forwarded to the Vice President of Power Markets for his approval.[44] In the event the Director has questions about or disagrees with an invoice, he attempts to resolve them by contacting a responsible individual at National Grid. If

[38] DR 158
[39] DR 771
[40] The Director of Generation Operations is also involved in the review and approval of major maintenance and capital expenditures at the PSA plants. This portion of his responsibilities is discussed in Chapter 11 – Capital and O&M Budgeting
[41] DR 158
[42] DR 158
[43] DR 158
[44] DR 158

these efforts are unsuccessful, he fills out an invoice-dispute form and withholds his approval of the disputed amount.[45]

- There have been instances where billing under the PSA has not complied with contractual requirements. In such cases, LIPA has disputed the items in question and ultimately resolved the matter with National Grid:

  - In late 2011, National Grid inspected, cleaned, and repaired an oil storage tank at Port Jefferson, in compliance with federal and state regulatory requirements. National Grid sought to recover the entire cost from LIPA under Article 7 of the PSA, which allows recovery of such compliance costs. LIPA maintained that the tank deterioration was clearly the result of aging, and therefore the responsibility of National Grid as a fixed-maintenance cost. National Grid ultimately agreed with LIPA, and withdrew its claim for reimbursement.
  - During summer 2010, National Grid billed LIPA $97,000 for operation of the Holtsville gas turbines at a rate which was meant to cover water treatment costs for emission control. Upon recognition that such charge was not in the PSA tariff, as well as a dispute involving similar billing under the EMA, National Grid reversed these charges in January 2011.[46]
  - In August 2010, National Grid-Genco sought to recover the full $649,000 of Port Jefferson dredging costs which exceeded the original estimates. LIPA disputed the amount and settled with National Grid for $532,500.[47]

18.3.5 LIPA's process to rely on National Grid for PPA invoice review and approval process is adequate.

- PAM reviews all PPA invoices using a checklist to document its review:

  - Prices are consistent with contract terms
  - Operational quantities are verified, including MWh purchased, Heat Rate and number of starts.
  - Supporting documentation reviewed
  - Calculations verified.[48]

- If PAM identifies any issues with an invoice, the group contacts the counterparty and requests additional back-up information and/or an updated invoice. If the issue(s) cannot be resolved by PAM, the invoice is forwarded to LIPA and with documentation of the issues and amount(s) in dispute.

- Upon review, LIPA Power Markets may either approve the total invoice amount approved by PAM or dispute some or all of the charges. Approved invoices are returned to Accounts Payable for processing.

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[45] DR 158
[46] DR 159
[47] DR 787
[48] DR 158

- Counterparties are notified of any disputed items and LIPA Power Markets and National Grid's PAM work with the counterparties to resolve the disputed items to the extent possible. Disputed items fall outside of the timely payment of invoice requirements in the PPAs.[49]

- NorthStar's review of invoices indicates that the checklists are completed and initialed, and the invoice details were verified.[50]

18.3.6 LIPA actively pursues opportunities to reduce purchased power costs and related costs of electric capacity and energy.

- LIPA Power Markets pursues PPA cost savings opportunities identified through reviews of invoices, assessments of market conditions, contract renewal processes, and contract claims negotiations. LIPA estimates it saved over $1.4 million during 2011-2012 through these activities.[51]

- Power Market's actions taken to reduce costs under the original PSA include:

  - Negotiated an agreement with National Grid to remove the Far Rockaway and Glenwood Landing power stations, the oldest and least efficient PSA plants, from the existing PSA, saving Authority customers $79 million through May 2013, and $179 million over the next 15 years (both, net present value) – including an $18 million cash payment to the Authority in equal installments in 2012 and 2013.[52]
  - Negotiated resolution of PSA and EMA billing disputes that clarified charges for unit start-ups, deionized water, and manual operation of remote-start PSA units.
  - Avoided over $30,000 in additional charges that GENCO had initially sought to impose and secured cancellation of unsupportable tariff charges.[53]

18.3.7 LIPA took adequate corrective actions in response to a recommendation in the 2009 OSC report on its Oversight of Contracts with National Grid.

- According to the PSA, National Grid is to send a notification letter to LIPA whenever it intends to sell its emission credits and offer LIPA that first right to purchase certain of the excess credits. If LIPA refuses the offer and National Grid sells the emission credits, LIPA is to receive 67 percent of the proceeds.

- The 2009 OSC audit found that because of an apparent oversight, National Grid did not report to LIPA the receipt of cash from credits sold, and as a results, LIPA did not receive $309,878 in auction proceeds. The report recommended that LIPA "[i]mprove the monitoring of National Grid's emission credit sales to ensure that LIPA receives its full share of the proceeds from these sales." [54]

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[49] DR 158
[50] DR 786
[51] DR 344 (confidential) and IS 202.
[52] DR 344, IS 199/200
[53] DR 344
[54] LIPA Oversight of Contracts with National Grid, OSC Report 2009-S-9

- LIPA's response to the OSC report stated "LIPA has enhanced its procedures to facilitate better coordination and communication between its internal departments and with National Grid. LIPA has also instructed National Grid to enhance its internal procedures to ensure that they promptly remit to LIPA its share of all emission credit sales, including EPA auctions."[55]

  - The enhanced process begins with an annual offer for the purchase of emission allowances from National Grid to LIPA; an offer which LIPA has consistently declined.
  - Each time a sale is completed, National Grid provides notice by e-mail and LIPA's Finance department verifies receipt of proceeds.
  - National Grid provides an annual summary report of its emission credit sales.
  - In addition, Power Markets independently monitors National Grid's emission allowance transactions using data reported by the US EPA on its website.[56]

18.3.8 The EMA and FMBSA contracts were relatively simple with minimal provisions for assessing the performance of the fuel contractor.

- The EMA called for the Fuel Manager to:[57]

  - manage all aspects of the fuel supply – both natural gas and fuel oil – for the PSA units, with some specification as to activities to be included in this service;
  - use "best efforts" to minimize fuel costs,;
  - provide accounting, bookkeeping and administration services associated with the fuel supply.

- The FMBSA has a similarly broad scope of services and also includes the purchase of both natural gas and fuel oil for the other units. This agreement only requires NGET to use "commercially reasonable efforts" to procure the fuel "at market prices."[58]

- The only measurement of the performance of NGET as the Fuel Manager was the EMA incentive/ disincentive clause, with the target defined as achieving 102% of market price for natural gas. The FMBSA has no provision to measure performance under the agreement and no incentive/penalty clause. Neither contract provided for any measurement of performance on the purchase of fuel oil.

- Using market price as a benchmark for fuel purchase performance is typical in the industry; targets are frequently set as a percentage plus/minus the market price, often with a deadband. Penalties are often mostly the responsibility of the fuel manager, upside incentives are more often shared.

[55] DR 879
[56] DR 789
[57] EMA, Article 3
[58] FMBSA Article III

18.3.9 LIPA has established appropriate policies, procedures and controls for the procurement of natural gas supply for generation.

- LIPA has developed a comprehensive package of policies and procedures intended to address all aspects of the short term Power Supply Management process (PSM Binder).[59]
- The PSM Binder includes procurement of natural gas and fuel oil supplies, establishment of PSA unit availability, tracking of PPA unit availability, and all aspects of the Power System Management (PSM) processes, discussed below.
- Natural gas procurement activities addressed in the PSM Binder include: forecasting of monthly gas supply requirements, determine the split between monthly and spot gas purchases, execution of the purchases, scheduling and monitoring of deliveries and processing of invoices. Essential transfers of information and data and needed coordination points between the Fuel Manager, the Power Supply Manager and LIPA are identified.[60]
- LIPA and NGET have an appropriate and sufficient pool of natural gas suppliers, and appropriately balance purchases between suppliers, while matching pipeline delivery capacities.[61]
- In addition, LIPA has established internal controls procedures for fuel procurement that outline the responsibilities of LIPA relative to monitoring of the fuel manager. Procedures for monitoring Fuel and Power contracts are general and do not specify what is to be done if LIPA is dissatisfied with what is monitored. [62]
- The natural gas procurement procedures clearly specify the nature and type of communications between LIPA, the Power Manager (CEE/PM), and the Fuel Manager (NGET) necessary to establish the volumes of gas needed for each month, and on a day ahead basis.[63] Documentation of natural gas purchases is appropriate for monitoring of transactions.

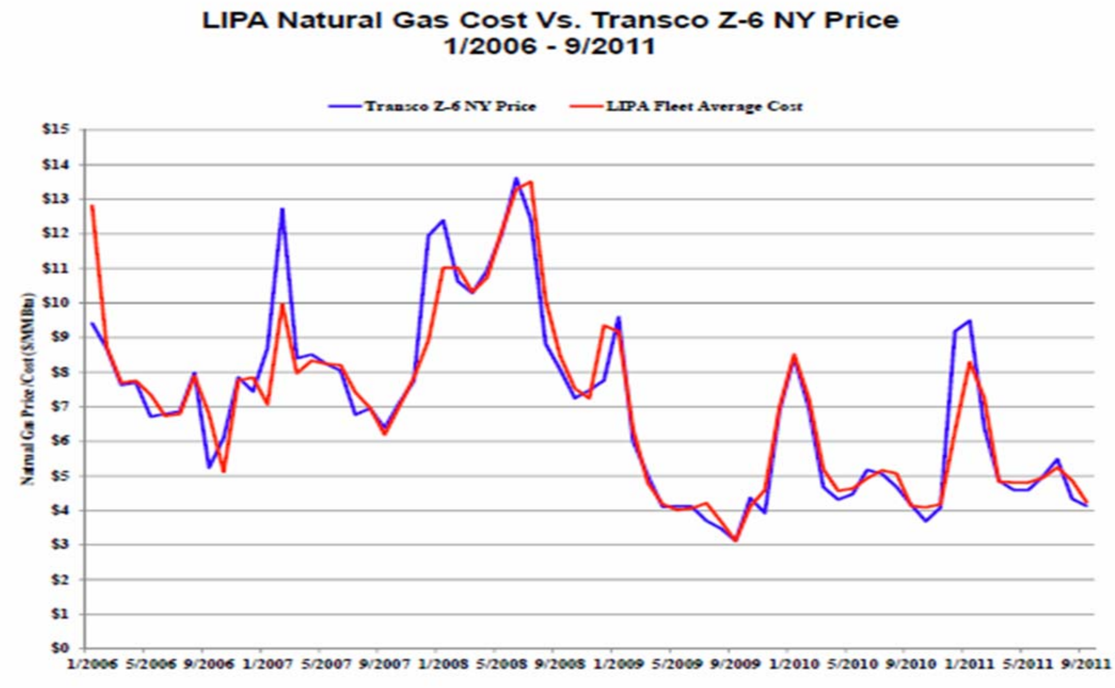
18.3.10 The prices of natural gas purchased by NGET on behalf of LIPA have been comparable with market prices, earning NGET significant incentive payments over the last three years.

- As shown in **Exhibit 18-6**, the price of natural gas purchased for LIPA has tracked very closely with the market price.[64] NorthStar's review of selected gas purchase

[59] DR 462 CONFIDENTIAL
[60] DR 462 and DR 158
[61] DR 828, DR 901, DR 823, DR 833
[62] DR 158
[63] DR 462
[64] DR 162

data over the past three years (through September 2012), verified that LIPA natural gas prices closely match market prices.[65] .

Exhibit 18-6



Source: DR 162

- From January 2010 through September 2012, NGET has been paid $7.3 million in incentives (net of penalties) under the EMA's incentive clause for natural gas purchases.[66]

- Review of data from selected months over that period identified very few instances where NGET incurred a penalty for gas purchased at prices greater than 102 percent of the market price. These few instances were generally for small dollar amounts. For example, in December 2011 NGET earned $176,348 in incentives and was charged $1,648 in penalties. Of the more than 130 gas purchase transactions that month only six were subject to the penalty. On all other transactions, NGET earned an incentive.

- Because there is no deadband for NGET performance, and the trigger for earning an incentive is 102 percent of the market price, NGET earns an incentive for purchases made at and below the market price. During December 2012, approximately 54 of the 130 transactions were at or within 102 percent of the market price, comprising approximately $60,000 of the $176,348 total incentives that month. One of the month-long base gas purchases was made at greater than market, but earned NGET over $50,000 in incentives

[65] DR 901
[66] DR 901

18.3.11 While oil products are only purchased occasionally and the prices paid have been generally consistent with market prices, the procurement of fuel oil is not as well documented as for natural gas.

- The importance of oil products in LIPA's fuel budget has declined from 64 percent in 2005 to between 10 and 13 percent now.[67] The decline in fuel oil consumption as a portion of the generation mix is the result of the recent relative price advantage of gas over oil, as well as a reduction in LIPA generation capacity with oil burning capability.

- Currently the procurement of fuel oil receives little direct attention; the procedures related to oil procurement are not fully documented, and oil transactions and prices paid are not part of standard reports from NGET to LIPA.[68]

- The PSM Binder includes an outline of the procedures to be used to determine the timing, volumes, and procurement processes for the purchase of liquid fuels. The outline is less detailed than for natural gas. The sample oil burn report provided in the Binder is no longer produced, and data related to oil transactions was not easily available.[69]

- Over the past three years (through September 2012), NGET has earned a net $1.3 million in incentives from the purchase of fuel oil. Several liquid fuel purchases are shown as having resulted in a penalty indicating the purchase price was greater than 102 percent of market.[70]

- Communications between LIPA, CEE and NGET related to possible use of fuel oil for generation and the level of fuel oil consumption was adequate.

18.3.12 The new FMA is very similar to the EMA/FMBSA in most areas and measurement of performance is still weak.

- The scope of services in the FMA is slightly more specific in the functions to be performed by CEE and reflect the current structure of the natural gas market.[71]

- The FMA has eliminated the incentive clause and replaced it with a performance penalty. Elements of the metric were expected to address the following measures of performance:

  - Gas Price Forecasting
  - Gas Purchase Price
  - Gas Balancing Charge
  - Enterprise Data Management

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[67] DR 162, 2013 Budget from website.
[68] DR 462 CONFIDENTIAL.
[69] DR 462.
[70] DR 901
[71] DR 870

- Overall Satisfaction
- Oil Price Forecasting
- Oil Purchase Price
- Oil Inventory Monitoring
- Contingent Event Monitoring
- Fuel Management Reporting Documentation
- Significant financial Loss

- The "Overall Satisfaction" metric was described as encompassing factors such as effective communication, accuracy and availability of market information, sound business judgment, and value-added recommendations – all of which are qualitative measures and difficult to both benchmark and document performance. Overall Satisfaction was to have a weighting of 20%, with the remaining ten metrics were each weighted at eight percent.[72]

- The FMA called for the parties to establish the computational details of the performance metrics no later than the start date for the contract (May 28, 2013). However, as of July 8, 2013, neither the benchmarks and trigger points, nor the computational details had been established for any of the metrics. As a result NorthStar cannot comment on their reasonableness or effectiveness in influencing positive performance by penalizing poor performance.[73]

18.3.13 The Fuel Procurement policies established by LIPA are transferable in major part to the new contractor.

- With the transfer of fuel management responsibilities to the CEE/FMA, the basic functions and necessary actions and transactions related to fuel procurement will not change. However, the CEE gas and fuel desks will undoubtedly have differences in the details of their processes

- LIPA has identified that it anticipates improved cooperation between PSM and Fuel procurement activities, enhanced reporting on fuel transactions, and fuel performance metrics.[74]

- The fuel management policies and procedures documented in the PSM Binder provide an appropriate basis for management and oversight of the new Fuel Manager.[75] However, changes to the Binder will be required as the specific processes used by CEE are clarified and processes are improved.

- LIPA intends for PACE to provide "middle office" management of natural gas and liquid fuel transactions in the future. This expansion of the scope of services is subject to a pending amendment to the PSMMO contract. Processes to be used for this monitoring and controls will be refined and specified in the PSM Binder.

[72] DR 902
[73] DR 870
[74] DR 832
[75] DR 462

18.3.14 LIPA has adequate internal, and going-forward, external resources assigned to the management and regular monitoring of the fuel management contracts; the company has responded appropriately to instances of non-compliance by the Fuels Manager.

- The responsibility for oversight of the Fuel Manager activities resides in the Power Markets Department.
  - The Director of Power and Fuel Operations has primary responsibility for oversight and coordination, and is integrally involved in the development of, monthly and daily fuel purchase plans.
  - The Director of Risk Management, who reports to the CFO, reviews fuel invoices on behalf of Power Markets due to his familiarity with the operations. In this review, calculations and supporting documentation are verified and prices paid are compared with the appropriate market data.
- The Office of the State Controller reviewed LIPA's management of all its contracts with National Grid, including the EMA. The OSC found that LIPA adequately monitored NGET's performance under the EMA.
- LIPA reported that it had not found instances where NGET's operational performance was not in compliance with contractual requirements. Given the very general nature of the required services and performance terms in the contracts, this is not surprising.[76]
- There were two instances in 2010 where billing under the EMA did not comply with contract specifications; LIPA disputed the charges and the items in question and ultimately resolved the matter with NGET:[77]
  - NGET billed LIPA for costs associated with some of the PSA units; these charges were challenged by LIPA and ultimately moved to the PSA.
  - LIPA determined that NGET had overcharged for oil spill response costs; the charges were challenged and the incorrect costs were reversed by NGET.

18.3.15 LIPA has not conducted an internal or outside audit of activities under either the EMA or PSA or of LIPA's oversight of these contracts during the last five years.

- As discussed elsewhere, LIPA has not had an Internal Audit function prior to late 2012; National Grid internal audits conducted in the past three years have not examined fuel procurement or power supply contracts.[78]

[76] DR 159
[77] DR 159
[78] DR 36

- Typically utilities include the fuel procurement and power supply processes in their Internal Audit plan on a frequent basis, due to the significant dollars involved and the possible impact on customer rates.

- With the initiation of the FMA, PACE Middle Office will begin monitoring the fuel purchases under the Middle-Office agreement. This additional step will provide valuable independent oversight and monitoring of the fuel procurement activities.

- The PACE Middle Office review does not replace the need for strong internal controls and periodic independent audits of the range of activities involved in planning for, procuring and documenting fuel supplies for LIPA's power plants.

- The initial Internal Audit plan prepared by LIPA's new Internal Audit group does not include any examination of fuel or power supply processes.

18.3.16 LIPA has an effective approach to managing its PSM activities using separate front, middle, and back-office processes and organizations.

- Prior to 2010, NGET managed the scheduling, bidding, buying and selling of power on LIPA's behalf in various power markets through the EMA contract. As part of the transition from National Grid's management of daily power supply activities, LIPA established the current front, middle, and back-office structure, which reflects the separation of responsibilities common in the financial services industry.

- **Exhibit 18-7** provides a summary of front, middle, and back-office PSM responsibilities.

Exhibit 18-7
Overview of Front, Middle, and Back-Office PSM Services

CEE Front Office PSM Services
▪ Forecast and bid LIPA's load obligations into the NYISO electric markets ▪ Set offer prices and communicate offers to the NYISO for generating resources that LIPA controls ▪ Arrange for capacity in bilateral markets and the NYISO administered auctions to meet LIPA's obligations ▪ Arrange for the import of power onto Long Island via the Cross-Sound, 1385, and Neptune cables, and scheduling those transactions with PJM and ISO-NE ▪ Estimate fuel requirements and coordinating with the Fuel Manager ▪ Advise LIPA on operating and strategic matters
CEE Back Office PSM Services
▪ Review invoices from NYISO, PJM, and ISO-NE ▪ Settling transactions with the ISOs and other counterparties ▪ Identify and follow-up on any settlement discrepancies ▪ Settling financial hedge transactions
PACE Middle Office PSM Services
▪ Monitor performance of front and back office services

Source: DR 164, Procedure 902, DR 601, PSM Middle Office Protocols and Procedures Final 2012, Initial Presentation

- PACE's current role as the independent middle office monitor of front office activity, is a new activity as of 2010.[79] Prior to 2010, NGET managed the scheduling, bidding, buying and selling of power on LIPA's behalf under the EMA, and LIPA was responsible for any performance monitoring.

- Along with the new structure for the PSM functions, LIPA and its contractors developed new processes and procedures for the conduct of daily PSM activities with an eye on cost effectiveness and increasing the economic utilization of the power system. LIPA tracks the savings attributed to changes executed by CEE, and reports savings in excess of $100 million.[80]

- As part of their activities during the transition from the National Grid EMA to the PSM contracts, CEE, PACE and LIPA mapped process flows and developed Administrative Protocols and Procedures to highlight services provided, the general manner in which the services were to be conducted, and formalized the functional relationships among the front, middle and back offices and LIPA. PACE also assisted LIPA in establishing performance metrics for the PSM Front and Back Office Service and in establishing management reporting systems.[81]

18.3.17 LIPA's Data Warehouse is an effective tool which supports the PSM activities of LIPA and its contractors.

- The LIPA Data Warehouse contains information relating to power supply management and fuel management services. Data is obtained from LIPA's PSM Partners (CEE, PACE and NGET for fuel procurement) and from the ISOs. Data includes:

    - Power sales and purchases, including bidding and scheduling information
    - Short term load forecast
    - Generating data (e.g., operational data, performance, dispatch notices, fuel consumption, emissions, scheduled maintenance and forced outages) for both PSA and PPA generating units under LIPA contract
    - Power purchase and sales contracts
    - Generation bidding and scheduling
    - Fuel purchase and tolling contracts
    - NYISO, PJM and ISO-NE information
    - Physical and financial hedging information[82]

- The Data Warehouse serves as the conduit between LIPA and its contractors. Multiple vendors can share data required from each other to accomplish their primary responsibilities.

    - CEE provides information to the Data Warehouse on bids, awards, and trades.

[79] DR 767
[80] DR 767
[81] Review of contracts
[82] DR 462

- PACE uses the information from CEE and NGET to monitor and validate the bids being submitted by CEE and measure the performance of CEE.

- The Data Warehouse was initially developed as part of the PSM implementation plan to facilitate the coordination of the myriad data points that are exchanged daily to execute daily power supply management.[83]

- The system is operated and maintained by LIPA IT staff with outside IT contractor support and is managed and backed up in compliance with LIPA IT protocols. Because this is a LIPA resource, there is no need for data or system conversion to bring in another data user, such as PSEG, or when a new Power Manager, Fuel Manager or other contractors are engaged.[84]

- LIPA IT Staff, with external contractor support, continues to enhance the Data Warehouse. After the initial implementation in 2010, additional projects were undertaken to enhance overall system reliability and to optimize trading operations:

  - A Disaster Recovery site was established to ensure continued PSM operations in the event that the primary site becomes disabled.
  - Archival processes for both data and documents were implemented to optimize system performance and allow long term retention of information.
  - Enhancements to the gas pricing information[85]

- In 2013, there were several project in progress to enhance the Data Warehouse, including:

  - Updating the system to support the transition of the Fuel Manager from NGET to CEE under the FMA
  - Development of new data flows to support the Dodd–Frank requirements to report information on certain trades
  - Updating the system to support the data requirements contained in the A&R PSA
  - Expanding the system to support Power Markets Fuel and Purchase Power Variance analysis and reporting system.[86]

- A planned Data Warehouse project would provide a Management Dashboard that would present summary data regarding performance of the power supply with the capability to drill down deeper for more detailed information about performance. The development of this project has been on hold pending hiring of LIPA staff to manage the project.[87]

18.3.18 LIPA manages its PSM contracts to effectively and efficiently balance reliability with low cost electricity for its customers.

[83] DR 349
[84] DR 349
[85] DR 466
[86] DR 349
[87] DR 466

- The primary responsibility of the Front Office is to submit load and generation bid formation into the ISOs.

- Bidding guidelines developed by the PSM Front and Back Office contractor to provide guidance for bidding and scheduling of LIPA's resources into the NYISO, PJM and ISO-NE markets. The principal rule and objective is to minimize the cost to serve LIPA's load. Generally, low cost is achieved by offering generation at its appropriate all-in cost, as well as purchasing energy on a least cost basis.

- Per the PSM contract, the bidding guideline calls for CEE to carry out the tasks required for "the purchase and sale of all capacity, energy ancillary services, and transmission congestion contracts on a 24 hours per day – 7 day week basis to meet the needs of Buyer's customer load in a least cost manner consistent with Buyer's existing agreements, policies, regulations, and reliability constraints."[88]

18.3.19 The PSM Back Office executes and supports an effective an ISO invoice process.

- The PSM Back Office is responsible for the review of ISO invoices to verify the accuracy of the settlements. When the PSM Back Office identifies any settlement discrepancies, it will submit the invoice-related dispute.[89]

  - Invoices from each ISO/RTO are compared with a shadow settlement in which CEE generates projected dollar balances from hourly prices and product quantities sold or purchased. [90]
  - Once balances are reconciled, invoices are passed to the LIPA Director of Power Markets Policy and ISO Reps for issue-level review to identify whether any of the disaggregated billing items (previously checked for accuracy) are exceptional or indicate any market design issues. Exceptional billing items are referred to the appropriate person for further exploration and explanation, and a strategy for identifying and addressing the market design issues is developed, including disputing bills that do not reflect tariff based treatment of items in question.
  - Finally, a LIPA officer, the Vice President of Powers Markets, provides final sign off on the invoices. [91]
  - ISO bills must be paid in a timely fashion even if disputed, thus invoices are approved for payment even if disputes are identified. Most invoices are due in 2 days.[92]

- The PSM Back Office is responsible for downloading the ISO invoices and tracking payments.

[88] DR 4
[89] DR 164 Exhibit G PSM Front and Back Office Procedures
[90] DR 663
[91] DR 663
[92] Various interviews

- After the Back Office downloads an ISO invoice and performs a reasonable check, it forwards the invoice to LIPA Accounting for monthly accrual and notification of payment.
- LIPA Accounting sends payment notification to PSM Back Office
- The PSM Back Office tracks payment aging. [93]

- The PSM Back Office heads the dispute resolution process. Billing disputes are pursued using each ISO's dispute process, and tracked in the PSM Back Office dispute tracking system. [94]

- The PSM Back Office Director of Settlements attends NYISO, PJM, and NE Billing and Settlement meetings to keep apprised of issues.[95]

18.3.20 The PSM Front and Back Office (CEE) contract has appropriate metrics, which are monitored by PSM Middle Office (PACE).

- LIPA's contract with CEE for front and back office Power Supply Management services contains performance incentives/penalties. The purpose of these metrics is twofold:

  - provide incentives/penalties to CEE to achieve measurable objectives. The achievement of those objectives will have tangible benefits for LIPA and its ratepayers in the form of decreased power supply costs and reduced risk to those costs.
  - provide feedback to LIPA and CEE. That feedback will be used by LIPA and CEE management to improve the strategies and tactics that LIPA and CEE will agree to and the process through which those strategies and tactics will be implemented.[96]

- Several of these metrics have been modified based on the first year's results (2010). The modifications reflect changes in operations and strategies and refine measurements of performance.[97]

18.3.21 LIPA effectively uses the PSM Middle Office (PACE) to monitor the PSM Front Office (CEE) daily power supply management activities.

- The PACE middle office is responsible for calculating the PSM Front Office performance metrics and assisting LIPA and CEE with interpreting those metrics to improve the service level provided by CEE. [98]

- PACE's oversight responsibilities are summarized in **Exhibit 18-8.**

[93] DR 164 Exhibit G PSM Front and Back Office Procedures
[94] DR 164 Exhibit G PSM Front and Back Office Procedures
[95] Various interviews.
[96] DR 601, PSM Middle Office Protocols and Procedures Final 2012
[97] DR 601, PSM Middle Office Protocols and Procedures Final 2012
[98] DR 601, PSM Middle Office Protocols and Procedures Final 2012

Exhibit 18-8
Pace Oversight Services

Performance Monitoring and Reporting	The middle office is be responsible for calculating those metrics and assisting LIPA and CEE with interpreting those metrics to improve the service level provided by CEE
Compliance Monitoring (Internal Governance: Strategy and Commercial Policies)	CEE's PSM contract calls for close consultation with LIPA and the on the strategies to 1) minimize cost to LIPA's ratepayers and 2) manage risks to within LIPA's tolerances. PACE's role in this is to: • Ensure those consultations occur and facilitate the exchange of information through compliance reporting • Provide suggestions to LIPA and CEE as to how policies and procedures and bidding strategies can be structured and described in a way that makes it possible to monitor them. • Provide information to LIPA and CEE on whether and how bids align with the agreed-to bidding strategies, policies, and procedures so that inadvertent breaches can be avoided • Detect deviation from agreed-to bidding strategies, policies, and procedures and report those deviations to LIPA
Compliance Monitoring (External Governance: Market and Regulatory)	PACE is responsible for: • Keeping CEE's bidding activities transparent in the context of the various rules and regulations so to prevent intentional breaches • Providing information and feedback to the PSMFB and LIPA that will assist it in avoiding inadvertent breaches of laws and regulations • Detecting breaches and immediately reporting them to LIPA so that LIPA can take corrective action
Compliance Monitoring (Internal Governance: Transaction Control Processes Monitoring)	The PSMMO will, therefore be responsible for: • Keeping CEE's bidding activities transparent in the context of the various rules and regulations so to prevent intentional breaches • Providing information and feedback to the PSMFB and LIPA that will assist it in avoiding inadvertent breaches of laws and regulations • Detecting breaches and immediately reporting them to LIPA so that LIPA can take corrective action
Fuel Interface Monitoring	Specifically, the PSMMO is responsible for: • Monitoring the fuel price forecasts communicated to CEE by NGETS, observing anomalies and reporting those anomalies to LIPA • Monitoring the fuel volume forecasts communicated to NGETS by CEE, observing variances between forecast and actual burn and reporting those variances to LIPA • Monitoring fuel supply by NGETS, observing variances between fuel supply and forecast and reporting those variances to LIPA • Reporting incidents of communication failure between CEE and NGETS to LIPA's attention
Credit Monitoring	Specifically, the PSMMO will: • Continuously measure LIPA's credit exposures • Compare those credit exposures to limits to ensure that they are consistent with LIPA's defined risk appetite • Evaluate new counterparty creditworthiness and ensure that the credit limits assigned to them are consistent with LIPA's risk tolerances
Support Risk Management Program	The PSMMO will provide information on power and fuel supply activities to the LIPA risk manager as requested, including (but not limited to) actual power and fuel volumes and prices.

Source: DR 601, PSM Middle Office Protocols and Procedures 2012 Final.

- PACE has detailed procedures to monitor CEE's Front and Back Office activities:

  - **Daily procedures** that are generally tied to the monitoring of daily bidding and transaction activities.
  - **Monthly performance and compliance** procedures that are generally tied to assisting LIPA in its financial reporting process, including the monitoring of transaction settlement and reporting of the performance of the Power Manager against the agreed-to metrics.
  - **Quarterly procedures**, particularly in support of certain accounting activities and the compilation of the overall satisfaction metric.
  - **Periodic or ad hoc procedure**s that are not tied to a specific schedule, such as the review of changes to bidding strategies and metrics associated with such changes or the addition of new trading counterparties.[99]

18.3.22 There are frequent communications, both formal and informal, between LIPA and its PSM contractors.

- LIPA's Director of Power and Fuel Operations monitors and manages the activities of CEE and PACE on a daily basis, including compliance with contract terms and conformance with LIPA's goals and objectives.[100] In addition to ad hoc communications to address specific issues, there are several established conference calls and meetings between LIPA and its PSM contractors:

  - LIPA's daily interaction with the PSM Front Office includes a daily "fuels call" to discuss the system dispatch results and going-forward strategy, review of recent performance and any subsequent corrective action, next day forecasted fuel requirements, ISO issues. [101]
  - LIPA's daily interaction with PSM Middle Office includes discussions covering report review, issue / incident review, and compliance issues. [102]
  - LIPA conducts a weekly operations call with all stakeholders, including the CEE, PACE, NG-Genco, NGET (now CEE's fuel desk), and PAM to discuss the pending week's operations. [103]
  - LIPA conducts a monthly in-person meeting with its Power and Fuel Managers to discuss, review and address any issues occurring during the past month's operations, as well as other items that impact LIPA's power supply management.[104]

- LIPA's PSM Middle and Back Office contractors also provide LIPA with a multitude of reports on daily power supply operations and settlement activities. A summary of reports is shown in **Exhibit 18-9 and 18-10**.

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[99] DR 601
[100] DR 164
[101] DR 164
[102] DR 164
[103] DR 164
[104] DR 164, IS 120, DR 480

Exhibit 18-9
PACE Middle Office Reports

Report Inventory	Reporting Frequency	Report Inventory	Reporting Frequency
Cable Schedule Effectiveness	Daily	Capacity Procurement	Monthly
Bid Reporting Documentation	Monthly	FTR-TCC Bid	Monthly-On Hold
Adherence to Bidding Strategy and Process	Monthly	Virtual Bids Compliance	Daily-On Hold
Contingent Responsiveness	Monthly	Bear Swamp Scheduling Compliance	Daily
Fuel Economics-Annual Gas Balancing	Monthly	Neptune Scheduling Compliance	Daily
Significant Financial Loss	Monthly	Transaction Activity	Daily-On Hold
PSM Enterprise Data Management	Monthly	Fuel Forecast Variance	Biweekly
Load Forecasting	Daily	Counterparty Credit Exposures	Daily
Load Bidding Compliance	Daily	CDS	weekly
Capacity Market	Monthly	Credit Concentration	Daily
Overall Satisfaction	Quarterly	Counterparty Financial Health	Quarterly
Bids Screening	Daily	Reserve and Regulation	Daily

Source: DR 601

Exhibit 18-10
CEE Back Office Reports

Report Name	Report Name
AR and AP Aging Report	Sales Report
Daily Trade Report by Counterparty	Hedge Transactions Invoices and Details
Daily Capacity Report by Counterparty	LIPA Gas Swap Settlements
ISONE Invoice	LIPA Power Settlements
ISONE Invoice Reconciliation Report	LIPA Oil Swap Settlements
ISONE Invoice Summary	LIPA Basis Swap Settlements
LIPA Cash Flow Report	LIPA Option Premiums
LIPA Hedging Summary	Allegro Basis, Power, Oil Gas Swaps
Monthly Hedge Reconciliation	Trade Confirmations
NYISO Invoice	Genco Steam & GT Reports
NYISO Invoice Reconciliation Report	LISF ADD & RTD Data
NYISO Invoice Summary	Caithness ADD & RTD Data
NYISO Working Capital Report	ADD Reports
NYISO Ancillary Charges Summary	LIPA Executive Report
Transmission Owners Report	LIPA PJM Dispute Tracking
TCC Auction	LIPA NYISO Dispute Tracking
PJM Invoice	LIPA ISONE Dispute Tracking
PJM Invoice Reconciliation Report	LIPA NYISO Mitigation Tracking
PJM Invoice Summary Report	SOC GEN Portfolio Reconciliation

Source: DR 459

18.3.23 CEE's two-day ahead forecast for the LIPA load is adequate.

- CEE utilizes Pattern Recognition Technologies (PRT), an outside service provider, to develop its two-day ahead energy forecast.[105]

  - PRT is an online load/price/wind generation forecasting service for the energy industry which provides short-term forecasts for wholesale electricity markets in North America. The PRT model is based on intelligent system technologies such as artificial neural networks, fuzzy logic and evolutionary computing. Forecasts are updated 24/7 with the most recent load/price/generation/weather data.
  - National Grid's Transmission Operations and Compliance group, which is responsible for the dispatch of the electric distribution system, contracts separately with PRT for short-term forecasting to maintain transmission system reliability. FERC requires that the transmission function employees operate independently from marketing function employees.[106]

- CEE has a monthly load forecasting performance metric of less than five percent error. During 2012, CEE achieved this benchmark every month except in July, when CEE reported a 5.8 percent error.[107] The metric calculations excluded data during Hurricane Sandy (October 29, 2012 thru November 4, 2012).

- NorthStar reviewed CEE's individual day load forecast performance and found the PRT model to perform adequately.

18.3.24 LIPA has a comprehensive set of energy risk management policies and procedures.

- LIPA's BOT has adopted a Governing Policy for Energy Risk Management (ERM Policy).[108] The ERM Policy establishes the philosophy, framework, and delegated authority necessary to govern LIPA's energy risk management program.

- The ERM Policy specifies that operations will be conducted with the objective of appropriate risk mitigation and never for purposes of financial speculation, and sets forth the following high-level hierarchy of energy risk management objectives:

  - **Tier 1 –** Business Objectives: The primary objectives of the Program are to constrain financial outcomes and rate requirements to acceptable levels, and to control risk management activities to govern transactional risks. The policy states that: "Under no circumstances shall transactions be executed which are not related to the Authority's core business objectives."
  - **Tier 2** - Risk Mitigation Objectives: Given volatile energy markets, manage energy input costs (and energy-related revenue where controllable) toward the

[105] DR 179
[106] FERC Order 889
[107] DR 455
[108] DR 54 & 224

mitigation of potentially unfavorable results and the promotion of results that fall within acceptable favorable boundaries.

- **Tier 3 –** Enhancement Objectives: Where achievable and with deference to Tier 1 and Tier 2 objectives, reduce costs or improve the Authority's net revenue surplus.

- LIPA has not entered into any Tier-3 transactions since inception of the Program. A sample Tier-3 transaction could involve selling call options against excess capacity, energy or fuels from on-island resources or inventory.[109]

- The ERM Policy appropriately restricts risk management hedging activities to mitigate actionable risk factors (e.g., natural gas, residual fuel oil, and power purchase requirements) that are quantifiable and material to LIPA's financial, operational, and regulatory performance; and sets forth permissible hedging instruments, and term and volume limits.

- LIPA's Energy Risk Management Committee (ERMC) is chaired by its Chief Financial Officer (Chief Risk Officer), and consists of the Director of Regulatory, Rates and Pricing, VP Power Markets, Staff Attorney, and a Vice President from PACE as a Non-Voting Ex Officio Member.[110]

- The ERMC has adopted a comprehensive Policies, Controls, and Procedures Manual for Energy Risk Management (Procedures Manual) that describes LIPA's risk management philosophy, identifies organizational elements of the Program, specifies risk management tools, and delineates responsibility and management control utilized to manage risk exposures.[111]

- The ERMC establishes LIPA's level of risk tolerance; approves risk management hedging strategies, hedging protocols, risk metrics, hedge volumes, traders, trading limits, and the extension of unsecured counterparty credit; and meets monthly, or as necessary, to administer the ERM Policy and provide executive management oversight of energy risk management activities. [112]

- The ERM Policy permits the unwinding of hedges, subject to constraints established by the ERMC; and the strictly limits the sale of options to collars, and cases where potential liabilities are fully offset by available assets.

- RiskSpectives, an energy risk management software system leased from and hosted by PACE, is used to capture hedge transactions; and to measure and monitor risk exposures, and the potential impacts that market price volatility has on LIPA's budget, net income, and customer rates. [113]

[109] DR 586
[110] DR 146, 224 & 226
[111] DR 224
[112] DR 57
[113] DR 14

- LIPA's two in-house traders authorized to execute financial hedging transactions communicate daily with Power Supply Managers that provide front, middle, and back office operations and support.[114]

- Section 2.06(c) of the Procedures Manual requires all financial hedging transactions to be linked to the purchase of sale of energy or energy products in connection with a core business function. For all financial hedges, the link must be documented on the same business day that the transaction is executed, and once documented, shall be irrevocable. Trades are assigned to a specific commodity book (e.g., minimum natural gas, minimum residual fuel oil) in RiskSpectives, and are summarized in Position Summary Reports.[115]

18.3.25 The BOT Finance and Audit Committee and the ERMC oversee and monitor LIPA's energy risk management program.

- The Finance and Audit Committee of the BOT is periodically briefed by the Director of Risk Management, and receives monthly briefing materials that include a comparison of fuel and purchased power costs (FPPC) vs. market prices, FPPC risk and risk mitigation, summary of hedging activities, collateral and mark-to-market trends, market fundamentals, ERMC activities, and changes in counterparty status.[116]

- PACE provides a comprehensive set of energy risk management monitoring and compliance reports to the ERMC on a weekly and monthly basis.[117] Members of the ERMC can access RiskSpectives to monitor energy risk management activities.[118]

18.3.26 LIPA's energy risk management program is sophisticated and focuses on constraining worst-cost outcomes, and due to its active nature, resembles a financial trading operation.

- LIPA ranks as the largest consumer of natural gas and oil among Large Public Power Council members, due to its necessary reliance on natural gas and oil-fired generation.[119]

- The market price of natural gas has been volatile and subject to event risks as shown in **Exhibit 18-11.**

- The primary objective of LIPA's hedging program is to constrain worst-cost outcomes with respect to fuel and purchased power, mark-to-market hedge losses, and option premiums.[120]

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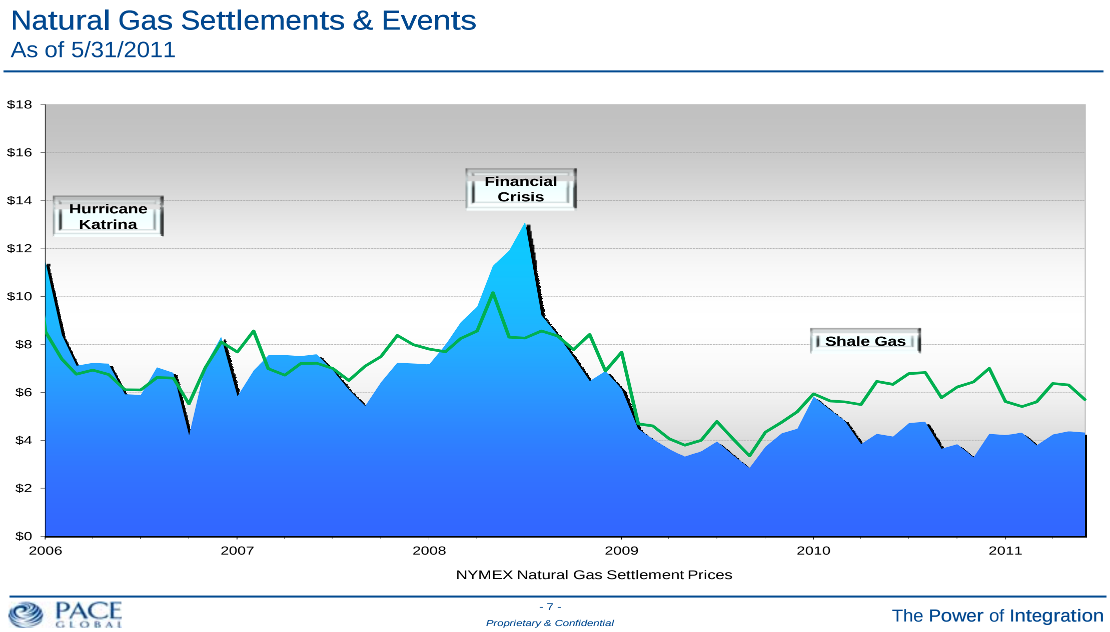
[114] DR 224 & 338
[115] DR 224 & 360
[116] DR 14
[117] DR 226, 303, & 304
[118] DR 57, 592, 589, & 810
[119] DR 590
[120] DR 226

Exhibit 18-11
Natural Gas Price Volatility



Source: DR 590

- LIPA financially hedges its exposures by deploying swaps and/or options, including a combination of fuel and/or basis swaps to hedge fuel costs, and heat-rate and fuel swaps to hedge purchased power costs.[121]

- Premiums and other costs associated with LIPA's fuel hedging program, including realized gains or losses on financial hedges, are recovered from customers through the Fuel and Purchased Power Cost Adjustment (FPPCA, i.e., Tariff Leaf 166).[122] LIPA's decision to hedge is based on established protocols consisting of mechanistic, conditional, and judgmental elements, described in **Exhibit 18-12.**

- LIPA has not executed any Discretionary hedges over the prior five calendar years.[123]

- The time horizons for hedging decision protocols are subject to revisions based on a number of factors, including market conditions (e.g., price and volatility), results of simulations, and changes in the level of risk tolerance. Typical time horizons for LIPA's hedging decision protocols are shown in **Exhibit 18-13**.

[121] DR 360
[122] DR 167
[123] DR 582

Exhibit 18-12
LIPA's Hedging Decision Protocols

Programmatic

- Hedges executed on a systematic time schedule to mitigate the onset of severe volatility
- Typically accumulated in small monthly increments 2 to 4 years prior to delivery
- Schedule is determined by ERMC

Defensive

- Hedges executed to mitigate the potential based on measured volatility for the 12-Month Rolling Average Cost (12RAC) of all fuel & electric requirements to exceed ERMC-established boundaries

Contingent

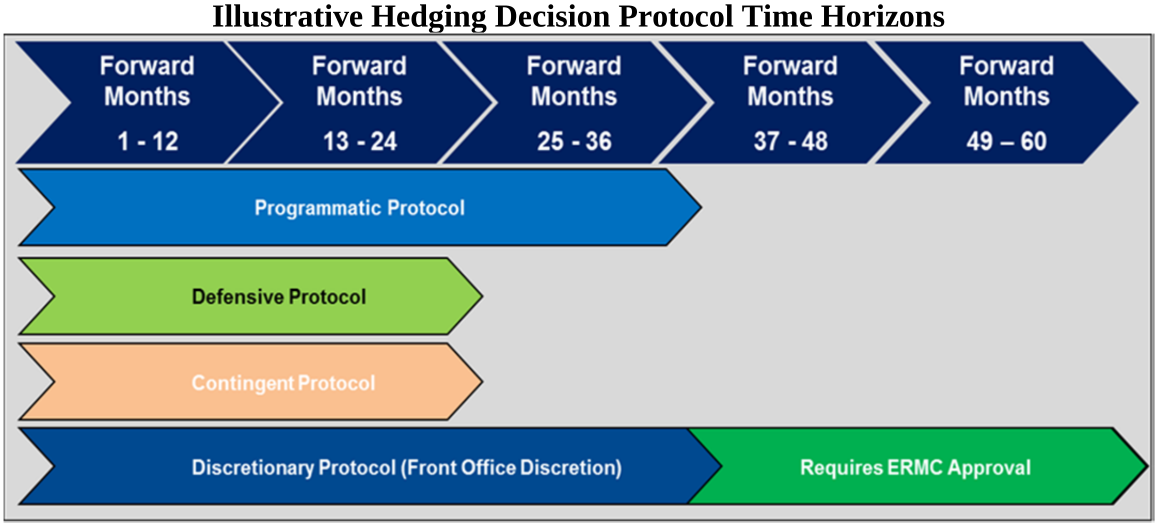
- Hedges executed in response to anomalous market conditions, particularly when price declines are so rapid as to create the potential for unacceptable mark-to-market losses on hedge transactions (i.e., Out-of-Market Outlier) and/or collateral posting requirements (Collateral Outlier)
- Out-of-Market Outlier metric is defined as the difference between the 12RAC that would result from a market price decline based on a 97.5% confidence level over a 90-day holding period, and the hypothetical that an unhedged portfolio would exhibit under the same circumstances (i.e., potential mark-to-market losses)
- Collateral Outlier metric represents the maximum tolerable collateral requirements due to out-of-the-money hedge transactions with counterparties.

Discretionary

- Hedges executed to take advantage of market opportunities characterized by the sentiment and momentum in the market.

Source DR 224

Exhibit 18-13
Illustrative Hedging Decision Protocol Time Horizons



Source: DR 590 (Proprietary & Confidential)
Note: The 36-month forward time horizon for Programmatic hedging is considered by PACE to be optimal; hedging strategies simulated using longer time horizons perform worse due to high premium costs associated with illiquid hedge positions, and those with shorter time horizons perform worse due to price volatility. (DR 584)

- The design of LIPA's hedging program involves the identification of a strategy and structure that is consistent with what PACE believes are LIPA's risk tolerances. The framework for identifying the hedge structure and risk tolerances is based on balancing the worst-cost outcomes with respect to the following three objectives[124];

  - Limiting the potential cost of fuel and purchased power to a specified dollar amount;
  - Managing the accumulation of financial hedges to limit mark-to-market losses to a specified dollar amount; and
  - Deploying options up to a specified annual dollar amount, as needed, to manage the tension between the maximum potential cost of fuel and purchased power, and mark-to-market losses on financial hedges.[125]

- The risk tolerance limits for each of the three objectives are evaluated by PACE, at least annually, based on complex simulations that use a range of input assumptions to produce alternative hedge structures. The most attractive hedge structures and a recommended hedge structure are presented to LIPA's Energy Risk Management Committee (ERMC) for consideration and approval. The approved hedge structure is the basis upon which PACE develops a tactical plan and specific actionable risk metrics for the Defensive and Contingent Protocol boundaries.[126]

  - The Defensive Protocol boundaries are set every month based on recent prices and volatility. If the boundaries are breached, additional hedges are accumulated up to established hedge ratios for each such boundary to mitigate the potential cost of fuel and power from exceeding established risk tolerances. Hedge ratios are revisited every six months, and are updated as market conditions warrant.[127]
  - The Contingent Protocol consists of the Out-of-Market Outlier and the Collateral Outlier. The risk tolerance for the Out-of-Market Outlier metric is 4.5 percent based on a 90-day VaR at a 97.5 percent confidence level.[128] The risk tolerance for the Collateral Outlier is $250 million for all forward years.

- LIPA's 2013 hedge strategy is to hedge 25 percent of its fuel and purchased power requirements over a forward 36 month time horizon by systematically executing swaps based on a specified schedule and percentage; and conditionally executing a combination of swaps covered by put options when the potential cost of fuel and purchased power exceeds specified boundaries up to predetermined hedge ratios.[129]

- In May 2011, PACE presented a comparison of the Maximum Hedge Ratio (i.e., first year of hedging) and Hedging Horizon for 20+ integrated utilities. The average Maximum Hedge Ratio for the peer group was 60 percent (i.e., primarily gas) and 86

[124] DR 594
[125] DR 303
[126] DR 303 & 590
[127] DR 303
[128] DR 226
[129] DR 303

percent (i.e., inclusive of multi-year coal contracts and in some cases nuclear), compared to 85 percent for LIPA. The average Hedging Horizon for the peer group was approximately 2.25 years, compared to 3.0 years for LIPA.[130]

18.3.27 LIPA's measures the effectiveness of its energy risk management program based on constraining unacceptable cost outcomes and not reducing the volatility of costs.

- LIPA's ERM Policy specifies that the effectiveness of all aspects of the energy risk management program shall be reviewed by the ERMC.[131]

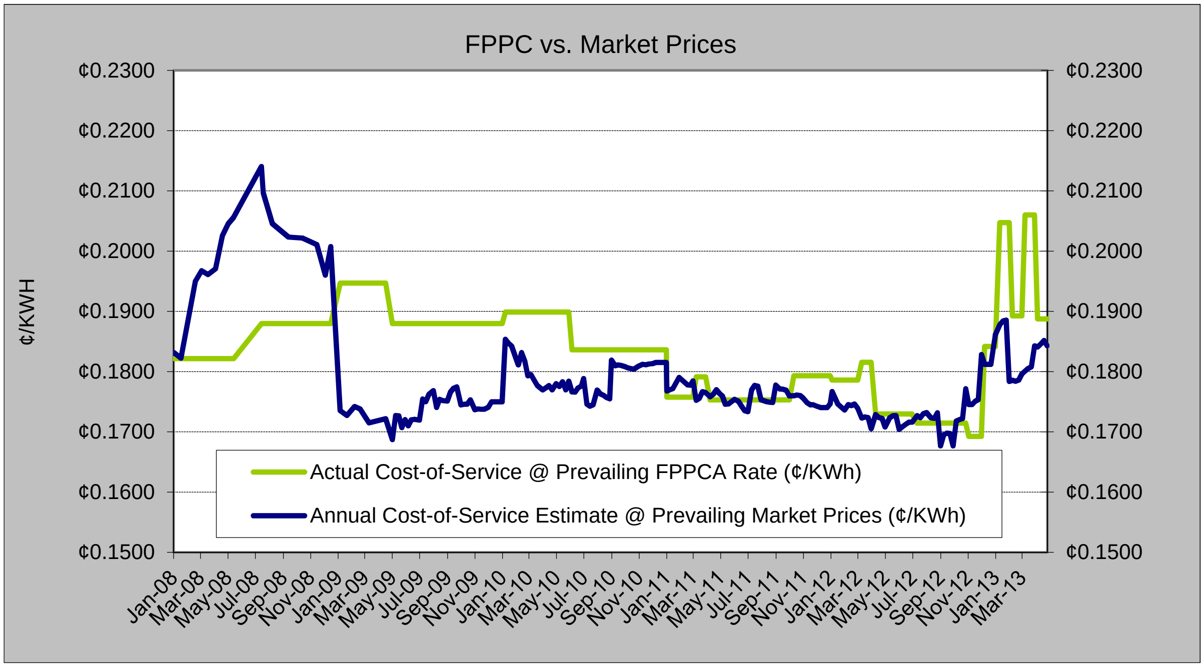
- The historical volatility of LIPA's system average delivered rate based on the actual cost-of-service at the prevailing fuel and purchased cost adjustment rate, compared to the annual cost-of-service estimate at prevailing market fuel and purchased power prices is provided to the Finance and Audit Committee of the BOT on a monthly basis.

- **Exhibit 18-14** illustrates the FPPCA rates compared to market prices from 2008 to the present. During 2008 the FPPCA rates, which include the results of the hedging program (shown as the green line) were well below prevailing market prices for natural gas (converted to c/kWh, the blue line). When market prices declined significantly in 2009 the FPPCA rates were above market prices – not unexpectedly since the hedge prices were largely set one to three years previously. Through 2010 to 2012, the FPPCA prices largely matched market prices, but without the month to month price variations. In late 2012 and 2013 natural gas prices increased, largely matched by the FPPCA rates.

- The performance of LIPA's hedge program for the period 2007 to 2010 was evaluated by PACE in early 2011. PACE determined the program be effective in mitigating risks as measured by the objectives to constrain the worst year-over-year market vs. actual increase in fuel and purchased power costs compared to budget; and worst year hedge loss compared to actual hedge loss. Based on these two measures, the worst year market cost increase during this period was $250 million in 2008, but LIPA's costs increased by only $34 million; and the worst hedge loss was $662 million in 2010, but LIPA's hedge loss was only $169 million. LIPA's hedge program performance compared to the worst outcomes is illustrated by LIPA's position above and to the left of the Worst outcome line as shown **Exhibit 18-15**.

[130] DR 590
[131] DR 54

Exhibit 18-14
Cost-of-Service at Prevailing
FPPCA Rate vs. Prevailing Market Prices

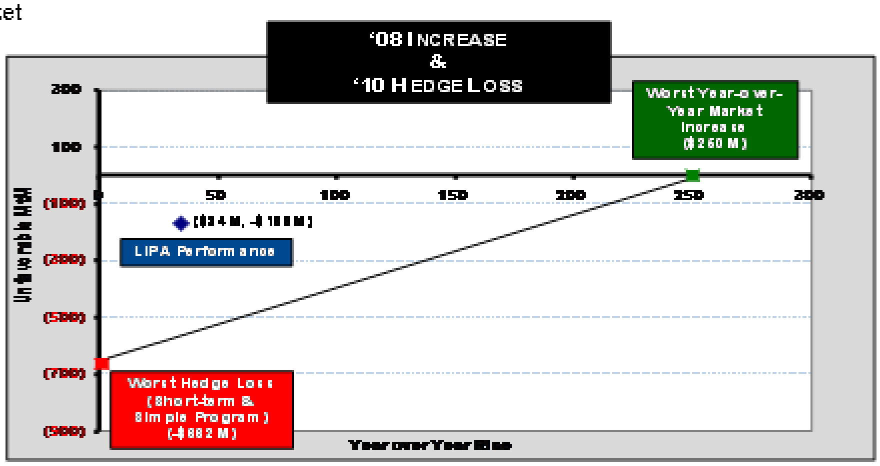


Source: DR 407

Exhibit 18-15
Hedge Program Worst Year Outlier Performance
2007 through 2010

PROGRAM OUTLIER PERFORMANCE

- Risk mitigation should be measured with respect to "outlier" performance; How did LIPA perform relative to how bad it could have been?
- The following chart plots worst-year hedge loss vs. worst-year cost-increase for the program and the market



PACE GLOBAL
- 23 -
The Power of Integration

Source: DR 590

18.3.28 Volumetric fuel and purchased power requirements for financial hedging purposes are consistent with that approved during the annual budget cycle, unless there is an unusual event that causes a dramatic change in volumes.[132]

- Many of LIPA's generating units located on Long Island are capable of burning either natural gas or fuel oil (i.e., dual fuel capable).[133]

- Dual fuel capability creates volumetric ambiguities that can reduce the effectiveness of hedges. To increase the effectiveness, PACE conducts an analysis of the fuel and purchased power budget during each budget cycle to determine the minimum natural gas, minimum residual fuel oil, and uncertain requirements (i.e., the Uncertain Fuel Mix Analysis). The fuel and purchased power budget volumes are adjusted based on such analysis, ratified by the ERMC, and entered into RiskSpectives by PACE. Financial hedges are executed up to the minimum requirements for each fuel type, and thereafter, the uncertain requirements based on least-cost at the time of execution.[134]

- Given that the price of natural gas is significantly lower compared to the price of residual fuel oil, the ERMC decided not to have PACE conduct the Uncertain Fuel Mix analysis for 2013.[135]

18.3.29 The cost to ratepayers of LIPA's energy price risk hedging program is relatively small compared to the annual fuel and purchase power expenditures.

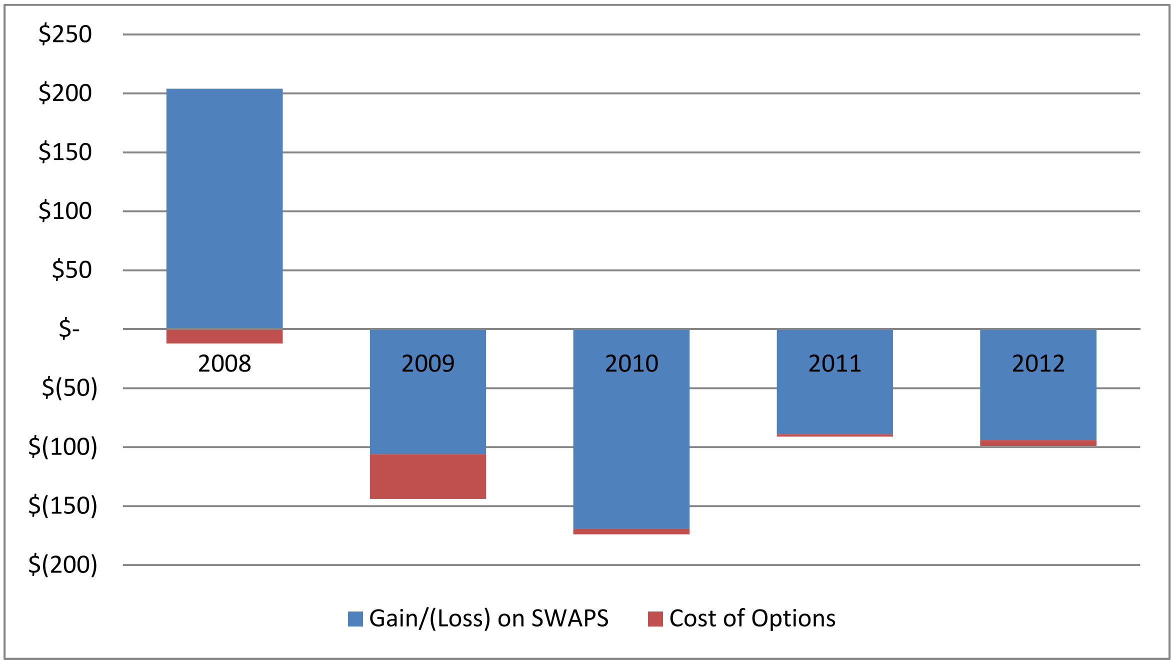
- Realized gains and losses on financial hedges and option premium costs should not be used to measure the performance of a hedging program, but they do provide a perspective regarding the cost of the hedging program.

  - In 2008 LIPA's hedging program showed a significant net benefit for ratepayers; since then the program has been a net cost, as illustrated in **Exhibit 18-16.**
  - As discussed, above, customers have benefited from the hedging program through reduction in price volatility since 2008.

- LIPA's net annual hedging loss as a percentage of annual variable fuel and purchased power costs for the period 2008 through 2010 was approximately 5.7 percent. During this period, the annual variable fuel and purchased power costs averaged approximately $1.16 billion and the annual realized gains and losses on financial hedges plus option premium costs averaged $63 million.[136]

[132] DR 226
[133] DR 160
[134] DR 224 and DR 590
[135] DR 303
[136] DR 162, Budget Information (lipower.org), & Audited Financial Statements (lipower.org)

Exhibit 18-16
LIPA's Realized Hedging Gains/(Losses) + Option Premium Costs
(In Millions)



Source: DR 162, Budget Information (lipower.org), & Audited Financial Statements (lipower.org)

- LIPA reports that since 2008 there has not been any benchmarking studies or reports that compare its day-to-day supply procurement with other utilities to determine if its program is more or less effective than other programs.[137]

18.3.30 LIPA's risk management function is appropriately staffed to provide a proper separation of duties.

- A Director of Risk Management reporting to the CFO is charged with execution of LIPA's Energy Risk Management Program and the hedging strategies established by the ERMC.[138] The Director of Risk Management, and the Director of Fuel and Power Operations who reports to the Power Markets organization are the only two traders authorized by the ERMC to execute financial hedges.[139]

- PACE, LIPA's External Risk Advisor is charged with recommending hedge strategies, hedge structures, and actionable risk metrics to the ERMC; ongoing monitoring of risk exposures; and communicating any breaches of established risk limits and violations of the risk management policies and procedures to the ERMC.[140]

[137] DR 664
[138] DR 390
[139] DR 224
[140] DR 224

- PACE also serves as LIPA's Power Supply Management Mid-Office under a separate contract. PACE reports that its organizational structure as it relates to work being done as LIPA's External Risk Advisor and PSM Mid-Office was designed to assure a segregation of duties.[141]

- LIPA's Credit Manager reviews the creditworthiness of potential counterparties and periodically monitors counterparty creditworthiness with assistance from PACE. Credit thresholds have been established and various credit monitoring and compliance reports are provided to the ERMC on a regular basis.[142]

- LIPA recently established an internal audit function. However, a formal policy has not been developed with respect to audits of energy risk management program activities.[143]

18.3.31 LIPA does not financially hedge fuel and purchase power costs by customer type. The complexities of allocating hedging costs to mass market customers would likely outweigh the potential benefits that could be achieved.

- LIPA does not financially hedge energy risk by customer type, but instead, hedges projected fuel and purchased power costs for all mass market customer classes.[144]

- The costs and benefits of LIPA's financial hedging program are shared by all mass customers through the Fuel and Purchased Power Cost Adjustment.[145]

18.4 Recommendations

18.4.1 Establish, or cause to be established, the performance metrics associated with the penalty clauses in the FMA, based on data such as external benchmarking and desired improvements in performance. The metrics should focus on performance that will provide benefits to ratepayers through encouraging least cost fuel procurement. Pricing metrics should be tested against past data (e.g., from the EMA period) to verify appropriate results and adequate penalties to preclude poor performance.

18.4.2 Improve, or cause to be improved, the documentation and reporting on fuel oil purchases under the FMA. Review existing processes for fuel oil procurement and management and propose modifications and improvements to bring the procedures related to fuel oil planning and purchases to a level commensurate with those in place for natural gas purchases.

18.4.3 Contract for an independent analysis comparing LIPA's energy risk management program to those at other utilities, and evaluate the benefits to ratepayers compared to the cost of the program, including option premiums and fees paid. The analysis

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[141] DR 589
[142] DR 224
[143] DR 748
[144] DR 362
[145] DR 167

should include whether similar price volatility reductions could be achieved at a lower cost through a less sophisticated program.

18.4.4 Include at least one aspect of the power supply management functions in the Internal Audit plan every year, so that over time IA would review the management of the power supply contracts, fuel procurement activities, near-term power system management, the middle office monitoring program, and the energy price risk hedging program.

19. LIPA's Fuel and Purchased Power Cost Adjustment Clause

19.1 Background

LIPA's initial tariff, adopted in its April 9, 1998 Rate Decision, included Leaf 166,[1] which set forth a Fuel and Purchased Power Cost Adjustment (FPPCA) clause. The FPPCA was derived from LILCO's existing Fuel Cost Adjustment, and was to be implemented beginning with the twelve month period starting January 1, 1999. The tariff lists the categories of fuel and purchased power and related costs to be recovered in the FPPCA and describes the rate calculation methodology. Fuel and Purchased Power Adjustment clauses have been adopted by numerous utilities, including the NYS investor-owned utilities. The intent of the clause is to allow the utility to recover the fluctuating fuel and purchased power costs by direct pass-through rather than embedding these costs in base rates. The FPPCA rate is referred to as the Power Supply Charge on customer bills.

There have been several modifications to the FPPCA since its inception. Such changes must be approved by LIPA's Board of Trustees, and are subject to the provision of State Administrative Procedure Act (SAPA), which specifies various requirements for public notice, including public meetings in Nassau and Suffolk Counties. **Exhibit 19-1** summarizes the Board-authorized changes to the FPPCA from its inception through April 1, 2013.

The Statement of Fuel and Purchased Power Cost Adjustment Rate (Statement) provides the actual rate used in computing bills to customers. The Statement shows the FPPCA rate and the effective date of the rate. LIPA's initial tariff required such a statement and that it be retained on file in its business offices. The Statement falls within the responsibility of the CFO; it is not required to be presented to the Board for approval, nor is it subject to the requirements of SAPA.

In 2009, LIPA retained Liberty Consulting Group ("Liberty") to conduct an independent evaluation of LIPA's recovery of costs through the FPPCA. Liberty reviewed LIPA's FPPCA tariff changes from May 31, 1998, through June 22, 2006, and Statements 1 through 21, which became effective May 1, 2009. NorthStar's review of the LIPA's FPPCA focused on the period after the Liberty audit, that is, the FPPCA tariff changes from June 23, 2006, through April 1, 2013, and Statements 21 through 35.

Current Tariff

On October 25, 2012, the Board approved revisions to the FPPCA which took effect November 1, 2012. There were two significant changes: 1) Elimination of net income targets and 2) moving from an annual to a monthly calculation of the FPPCA rate.

[1] A "leaf" refers to the numeric designation used to locate the applicable section of the Tariff, similar to a page number.

Exhibit 19-1
FPPCA Tariff Changes

Meeting Date	Board Action
May 31, 1998	LILCO-based tariff adopted, including FPPCA.
March 1, 2001	Board resolution approved, providing for partial recovery of Excess Fuel Costs: $318 million in fuel costs incurred above the amount included in base rates for year 2000, netted against $22 million recovery above the amount in base rates from 1998; resulting in a net shortfall of $296 million. Funding of $296 million as follows: LIPA will recover $125 million though FPPCA, will meet the balance of $171 million through a change to the accelerated Shoreham-related debt retirement. Adopted on an emergency basis under provisions of SAPA.
June 28, 2001	March 1, 2001 resolution adopted on a final basis.
February 28, 2002	Board resolution approved, providing for partial recovery of Excess Fuel Costs: LIPA incurred $200 million in unrecovered fuel costs during the year 2001. LIPA will recover $125 million though the FPPCA and the remainder of $75 million through a change to the accelerated Shoreham-related debt retirement. Adopted on an emergency basis under provisions of SAPA.
May 21, 2002	February 28, 2002 resolution adopted on a final basis.
February 27, 2003	Board resolutions approved, providing for partial recovery of Excess Fuel Costs and other changes: • LIPA incurred $254 million in unrecovered fuel costs during the year 2002. LIPA will recover $129 million though the FPPCA. • Begin transition to current year recovery, rather than one year lag, by recovering $75 million of expected 2003 Excess Costs beginning in March 2003. • Defer $70 million of expected 2003 Excess Costs for recovery through FPPCA in 2004. • Institute the Reserve Margin of revenues over costs of $20 million for the remainder of 2003 and going forward. • Defer remaining 2003 Excess Costs and recover over 10 years.
February 10, 2004	Board resolutions approved, providing for 10 year amortization of all 2003 Excess Costs, including the $70 million that was to have been collected in 2004.
April 27, 2006	Board resolution approved to: • Change the Reserve margin from $20 million to $75 million, plus or minus $50 million. • Update and modify the tariff language describing FPPCA components.
June 22, 2006	Board resolution approved to move a fixed amount of fuel and purchased power costs included in base rates to the FPPCA. In order to make the change revenue neutral for all classes, minimum charges for certain rate classes were changed, as those charges were stated in terms of fixed dollar amounts.
October 25, 2012	Board resolution approved to: • Eliminate net income target. • Authorize full recovery of LIPA's fuel and purchased power costs and reflect monthly changes in pricing (monthly rather than annual recovery). • Eliminate annual forecasting of fuel and purchased power costs for FPPCA billing purposes. • Clarify certain aspects of the tariff

Source: DR 167 and DR 165

- **Switch to Monthly FPPCA Pricing –** Prior to the October 2012 modifications the tariff provided for recovery based on annual projections of fuel and purchased power costs. LIPA modified the rate during the year, but did not change the projected costs used to determine the rate. The revised FPPCA allows LIPA to recover projected costs for each coming month, plus any variances in recovery (positive or negative) from prior months.

- **Elimination of Net Income Target** – In February 2003, LIPA changed its tariff to include a net income target as a component of the FPPCA. LIPA initially set this "excess of revenues over expenses," generally similar to net income, at a target of a flat $20 million, with no tolerance band. In April 2006, LIPA increased this target to $75 million, and added a tolerance band of plus or minus $50 million. In no event, would this mechanism allow the Authority to recover an amount that would exceed its incurred fuel and purchased power costs. The Tariff authorized increases to the FPPCA to reflect higher fuel expense only in the event that projected net income falls below $25 million for the year. The October 2012 Board Action did away with this target.

The current categories of costs included as fuel and purchased power costs in the FPPCA tariff are specified in **Exhibit 19-2**.

Exhibit 19-2
Categories of Fuel and Purchased Power Costs in the FPPCA

Category	Costs
Fuel and Purchased Power Costs	Purchased fossil fuel Nuclear fuel purchased for NMP2 NMP2 nuclear fuel disposal, decontamination and decommissioning costs Power purchased from NYPA, other utilities, IPPs, QFs and customer generators Costs incurred under any power supply management agreement or fuel management service agreements Renewable power costs Premiums and other costs associated with LIPA's fuel hedging program, including gains and losses
Transmission	Transmission wheeling and other charges including off-island facilities
Dispatch/Reliability-Related	Charges for capacity, energy, scheduling, system control, dispatch and ancillary service paid as a result of participation in ISO markets Other net charges (net of revenues) associated with transmission congestion contracts, ancillary services and short-term capacity received by LIPA as a participant in ISO markets
Emissions Credits [Note 1]	Fuels costs and value of foregone emissions credits that partially offset revenues credited from energy sold to other utilities, power marketers, or other brokers who are not agents of LIPA retail customers
Other	Payments to customers who shed load at LIPA request Bill Cost Adjustment payments to energy service companies and direct retail customers under the LI Choice program

Source: FPPCA Tariff effective November 1, 2012.
Note 1: LIPA does not sell energy off-system, so this category is not used.

The FPPCA rate includes elements in addition to the current cost of fuel and purchased power. Currently, FPPCA rates include:

- A component to offset prior years' revenue over-collections due to a change in LIPA's unbilled revenue methodology.[2]

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[2] DR 365

- A component to reflect amortization of 2003 excess fuel and purchased power costs.

The FPPCA is calculated by dividing the projected month's cost of fuel and purchased power and LI Choice bill credits by the projected month's energy sales and including a true-up based on the prior period's actual costs, plus additional costs to amortize prior deferred balances.[3] **Exhibit 19-3** provides an overview of the calculation and data sources.

Exhibit 19-3
Overview of Monthly FPPCA Recovery Rate Calculation

$$\text{Month 3 FPPCA Recovery Rate} = \frac{\begin{array}{c}\text{Month 1} \\ \textbf{Actual}\text{ Amount} \\ \text{Under-Collected} \\ \text{(\$)}\end{array} + \begin{array}{c}\text{Month 2} \\ \textbf{Projected} \\ \text{Amount Under-} \\ \text{Collected (\$)}\end{array} + \begin{array}{c}\text{Month 3} \\ \textbf{Projected} \\ \text{F\&PP Costs} \\ \text{(\$)}\end{array} + \begin{array}{c}\text{Other} \\ \text{Adjustments} \\ \text{(\$)}\end{array}}{\text{Month 3 Projected Sales (GWh)}}$$

A summary of cost elements included the FPPCA Statements in effect during the audit period is shown in **Exhibit 19-4**. In some periods, such as in 2012, the rate included several components to refund over-collections as well as to recover excess refunds.

Exhibit 19-4
Line Items in FPPCA Statements

Statement	Statement Effective Date	Average Cost of Fuel and Purchased Power	2003 Amortized Excess Fuel and Purchased Power Costs	Offset Prior Years' Over-collections related to Unbilled Revenue	Refund Prior Year's Over-Collection	Recover 2009 Excess Refund	Recover 2010 Excess Refund	Refund 2010 Over-collection	FPPCA
21	5/1/2009	10.1555	0.1820		(0.0126)				10.3249
22	1/1/2010	10.4613	0.1851		(0.7345)				9.9119
23	6/1/2010	10.4180	0.1871		(0.9247)				9.3042
24	1/1/2011	8.9271	0.1844		(0.7249)				8.3866
25	4/1/2011	8.9271	0.1844	(0.3696)	(0.7249)				8.0170
26	10/1/2011	9.3153	0.1844	(0.3696)	(0.7249)				8.4052
27	1/1/2012	8.1975	0.1792	(0.1792)		0.0451	0.0528		8.2954
28	4/1/2012	7.5226	0.1818	(0.1804)		0.0423	0.0527	(0.1565)	7.4626
29	7/1/2012	7.3746	0.1855	(0.1875)		0.0433	0.0556	(0.1663)	7.3089
30	11/1/2012	7.1590	0.1748	(0.1743)		0.0412	0.0469	(0.1580)	7.0895
31	12/1/2012	8.6419	0.1848	(0.1818)		0.0429	0.0611	0.1668	8.5821
32	1/1/2013	10.6377	0.2007	(0.2015)					10.6369
33	2/1/2013	9.0894	0.1915	(0.1943)					9.0866

Source: DR 172 and DR 364

Ultimately, the ratepayers never pay more than the actual cost of fuel. The determination of over- and under- collected amounts is based on actual revenues and fuel and purchased power costs.

In the period May 2006 through October 2012, LIPA would absorb any fuel costs that exceeded the FPPCA revenue recovered from customers if its net income exceeded the $25

[3] Current FPPCA tariff, LIPA website, NorthStar review of DR 172

million net income target ($75 million +/- $50 million). Excess cash generated from operations was used to absorb fuel costs incurred in excess of the amounts recovered in rates.

In 2006 and 2007, LIPA collected more than incurred, and thus established regulatory liabilities at each year end. LIPA returned the excess recovery to customers over the subsequent 12-month period.[4]

- In 2008, the Authority under-collected fuel costs totaling $143.5 million, but as it was operating under the 2006 FPPCA modification, and net income was $26.9 million (above the $25.0 million floor), it had no ability to seek recovery of those excess fuel costs, and as such these charges were considered absorbed.[5]
- For 2009, 2010 and 2011, the Authority over-recovered fuel costs and established regulatory liabilities at each year end to return such over-collections to the customers in the subsequent period.[6]

LIPA has absorbed over $1.0 billion in fuel costs since 2001.[7] In 2002, the Board authorized recovery of an amount less than the total fuel and purchased power costs; and in 2004 and 2005, per the tariff in effect at the time, LIPA only collected excess fuel costs to the extent that its net income would not exceed $20 million.[8]

19.2 Evaluative Criteria

- Is LIPA's FPPCA Tariff clear, useful and comprehensive? Do the actual costs recovered correctly reflect what is allowed under Tariff Leaf 166?
- Has LIPA implemented its fuel and purchased power tariff in compliance with the requirements specified in the tariff?
- Are the costs included in LIPA's clause recovered exclusively through that clause, or are they also included in other rates and charges?
- Are the projections of future fuel costs incorporated in the Power Supply Charge reasonable?
- Does LIPA maintain sufficient historical financial records for a reasonable time frame to assist with the verification of fuel and purchased power cost?
- Does LIPA have effective policies, procedures, and processes for determining the correct cost recovery amounts?
- Does LIPA have effective policies and procedures for approving changes to cost recovery?
- Does LIPA have effective policies and procedures for verifying cost recovery under the adjustment clause?
- Do LIPA' day-to-day practices comply with the requirements specified under its fuel and purchased power policies and procedures?
- Are the charges recovered through the FPPCA approved by the appropriate managers and Authority's Board of Trustees?

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[4] DR 243
[5] DR 666
[6] DR 243
[7] DR 243
[8] DR 243

19.3 Findings and Conclusions

19.3.1 The modifications to the FPPCA tariff adopted by the Board on October 25, 2012, improved the clarity of the tariff, simplified the FPPCA calculation, and provide better cost signals to customers.

- The switch to using monthly, rather than annual, projections of fuel and purchased power costs is beneficial to both LIPA and its customers. By moving to monthly cost recovery, customers are charged for the fuel and related costs based on their consumption on a month-to-month basis which allows:

  - Better identification of the relationship between usage and cost for customers as a whole.
  - Higher savings to the customer from efficiency efforts that are targeted towards the more expensive summer months, and increased focus and attention on LIPA's peak load conditions.
  - More timely cash flow to LIPA, as cost recovery occurs more closely to expenditure.
  - An end to the annual forecasting of fuel and purchased power costs for FPPCA billing purposes that can lead to over or under-recovery from customers.[9]

- The elimination of the net income target allows LIPA to recover 100 percent of its power supply costs. Previously, if LIPA's fuel and purchased power expense exceeded the Power Supply Charge (FPPCA) revenue recovered from customers, LIPA absorbed that difference if its net income exceeded the $25 million net income target ($75 million +/- $50 million).

- The October 2012 tariff modifications clarified the definition of "Purchased Power" to more clearly reflect LIPA's existing practice. The definition was expanded to clarify that revenues from the sale of energy to other utilities and marketers are used to offset the expense of purchased power.[10]

19.3.2 LIPA has adequate controls to ensure the accurate assignment of actual costs to the FPPCA. LIPA does not recover any inappropriate costs through its FPPCA.

- FPPCA costs and revenues are tracked in specific general ledger accounts.

- Each month the accounting department analyzes the fuel and purchased power accounts (i.e. comparing year-to-date (YTD) activity to the prior YTD activity, month-to-month activity, and other analyses) to ensure that such costs are properly stated based upon the information made available to the accounting department, including invoices, e-mail messages or phone conversations with various operating groups and out-sourced personnel. Upon satisfaction that all costs have been accounted for appropriately, the accounting group will prepare a summary of such

[9] DR 167
[10] DR 167

costs on a year-to-date basis. This summary will be compared to the general ledger to ensure all cost categories are included on the summary.[11]

- NorthStar's review of the line items in the FPPCA cost accounts identified confirmed all line items were related to costs specified in the tariff.

- NorthStar's detailed testing of sample of transactions in the monthly FPPCA calculations did not identify any exceptions.

19.3.3 Some of the power supply cost types included in the FPPCA clause are also included in LIPA's Delivery Charge; however, the same costs are not included in both the FPPCA and the Delivery Charge. This complicates the implementation of the ReCharge NY Power Program and may lead to ratepayer confusion.

- LIPA's Delivery Charge includes component that recovers certain generation costs, including the Power Supply Agreement and expenses related to the Nine Mile Point power station. These components are legacy rate components from the Long Island Lighting Company's former rate structure (which was adopted by LIPA as of the May 1998 LILCO/LIPA merger). [12]

- Expenses associated with generation represent approximately 30 percent of LIPA's total Delivery Charge, and are comprised as follows:

  - Power Supply Agreement Expenses
  - Operating and Maintenance Expense on Nine Mile Point 2
  - Accretion of Asset Retirement Obligation on Nine Mile Point (net of trust income)
  - Depreciation Expense on Nine Mile Point 2
  - Property Taxes on Nine Mile Point 2
  - Interest Expense on Investment in Nine Mile Point 2
  - Property Taxes on Merchant Generation[13]

- Per the FPPCA tariff, the cost of fuel and purchased power includes "total actual cost of all electric power purchased by or on behalf of the Authority from the New York Power Authority (NYPA), other utilities, and independent power producers..."[14] The costs of LIPA's Power Supply Agreement with National Grid meet the definition of costs of "electric power purchased;" however, LIPA does not recover these costs in through the FPPCA.

- Nine Mile Point 2 costs are separated between the FPPCA and the Delivery Charge.

  - The FPPCA tariff includes the costs of nuclear fuel, nuclear fuel disposal, Nine Mile Point 2 decontamination and decommissioning,

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[11] DR 168.
[12] DR 671
[13] DR 671
[14] LIPA Tariff Leaf No 166

- The Delivery Charge includes Nine Mile Point 2 O&M, depreciation, taxes, interest expense, and the accretion of the asset retirement obligation.[15]

- Renewable power costs are recovered through the FPPCA. LIPA does have an Efficiency and Renewables Charge, which is limited to recovery of rebates and incentives paid to customers and associated program administration costs.[16]

- LIPA instituted a 30 percent Delivery Charge discount to ReCharge NY customers to ensure that the inclusion of power supply costs in the Delivery Charge does not impact the implementation of the ReCharge NY program from a rate perspective.

  - The ReCharge NY Program started on July 1, 2012. Under ReCharge NY, NYPA provides lower-cost power to eligible industrial and commercial customers. ReCharge NY Customers pay NYPA for the power.
  - NYPA provides all of the generating capacity requirements, which ReCharge NY participants pay to NYPA. From LIPA's ReCharge NY customers' perspective, the base rate Delivery Charge includes capacity costs that they are not using.
  - All of the State's electric utilities were required to modify their respective tariffs to provide for delivery of ReCharge NY power at discounted rates to participating customers in their respective territories. The PSC ordered the IOUs to excluding the System Benefits Charge, the Renewable Portfolio Standards surcharge, the Energy Efficiency Portfolio Standards surcharge, as well as the Revenue Decoupling Mechanism from Delivery Charges for ReCharge NY power allocations.
  - A ReCharge NY discount of approximately 30 percent was adopted by emergency action of the Trustees at the October 2012 board meeting and permanently approved at the January 2013. The 30 percent discount of LIPA's Delivery Charge was implemented, retroactive to July 1, 2012 in order to ensure that LIPA's ReCharge NY customers are not economically harmed by the unintended consequence of LIPA's rate structure.
  - The amount of the discount is to be recalculated on an annual basis. [17]

19.3.4 The LIPA personnel responsible for the FPPCA rate have significant experience developing the FPPCA rates and perform the calculations in accordance with the tariff; however, LIPA's draft document outlining the steps to calculate the monthly FPPCA does not clearly define all data flows.

- The three principal organizations involved in the monthly rate calculation are: Regulatory Rates and Pricing ("Rates"), Planning and Budgeting, and Accounting.

  - **Financial Planning and Budget –** collects and compiles the projected costs of fuel and purchased power for each future month. Obtains forecasted fuel and purchased power expenses from Power Markets.

[15] LIPA Tariff Leaf No 166
[16] DR 171
[17] DR 671

- **Regulatory, Rates and Pricing** – establishes the FPPCA rate based on expenditures and recovery of the eligible costs, and distribute the monthly FPPCA rate to all users.
- **Accounting –** records the actual expenditures and recovery of fuel and purchased power costs, and records any balances owed-to or owed-from customers on a monthly basis.

- The individuals with primary responsibility for the FPPCA calculation have been involved with the process for several years.

- The Rates and Pricing staff calculate the FPPCA rate to recover the projected costs for the coming month and adjusts the rate for any over-and under-recovery for the year to date. It also updates other components of the FPPCA, such as the Amortization of the 2003 Deferred Fuel Expenses and the Adjustments for Unbilled Revenue. The FPPCA calculation is a spreadsheet process. The major inputs and sources to the calculation are shown in **Exhibit 19-5**.

- The draft "Plan of Administration of Calculation of the FPPCA" documents the steps taken by the various LIPA groups to provide input to the FPPCA calculation, but there are some gaps in the documentation, and it has not been approved by senior management or the Board of Trustees.

19.3.5 LIPA has an informal, yet effective verification process for its monthly FPPCA rate calculation.

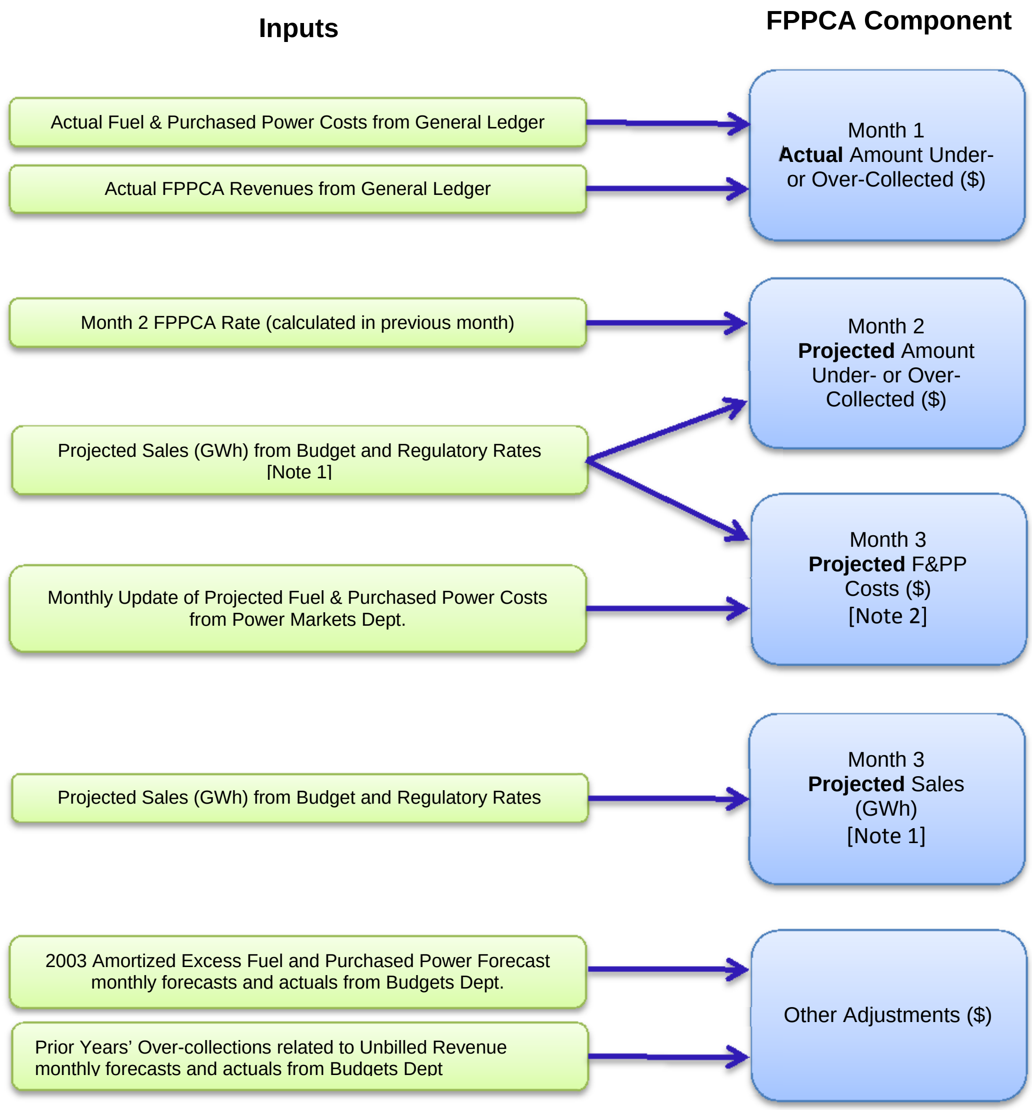
- The Rates, Planning and Budgeting, and Accounting groups each separately determine the actual over- or under- collected amount to be used in the calculation. The three groups communicate their results via email, and follow-up on any differences.[18]

- As part of the spreadsheet calculation process, Rates compares the expected revenue based on GWh sales and the FPPCA rate to the actual recorded revenues.

- The Planning and Budgeting group does a "shadow process" of the Rates group's FPPCA calculation before the Rates group distributes the authorized rate to the billing department and elsewhere.[19]

[18] Various interviews and working sessions
[19] DR 168

Exhibit 19-5
FPPCA Calculation Inputs and Sources



Note 1: FPP costs are adjusted for the Brookhaven National Laboratory's (BNL) power costs
Note 2: Revenues are adjusted for ReCharge NY service, BNL Service, and LI Choice service.
Source: DR 168 and DR 172

19.3.6 LIPA's projections of future fuel costs incorporated in the Power Supply Charge are reasonable.

- Power Markets projects the fuel and purchased power expenses for future months using MAPS (Multi-Area Production Simulation), a production simulation model.
  - Projections of commodity prices for future months are obtained from the forward price strips in the relevant natural gas, fuel oil and purchased power commodity markets using a recent ten trading days, average and adjusted for any differentials in basis (location).

- MWh sales and load forecasts are reviewed quarterly for potential adjustment based upon recent experience and updated econometric data.
- These updated commodity prices and potential MWh sales and load adjustments are then incorporated into the MAPS dispatch simulation of projected load, requirements and generation to determine the projected cost of fuel burned and energy purchased for the coming months.

- Additional adjustments are then incorporated to the cost projections to reflect changes in financial hedge results, changes in payments made to LI Choice ESCOs, and any other changes to costs that are identified.

- The cost of power provided by the NYPA to support the former Power for Jobs program and the BNL Hydro contract are then deducted to determine the costs eligible for recovery under the FPPCA.[20]

19.3.7 In 2009 and 2010, the FPPCA rate was calculated to create a specified reduction in customer bill amounts, not to target a specific income level as specified in the tariff.

- Prior to the October 2012 tariff modification, the FPPCA tariff provided for recovery based on annual projections of fuel and purchased power costs. At the start of each calendar year, the Power Supply Charge and all other rate components were set at a level designed to achieve a financial target of $75 million. During the year, the Authority would monitor, and if necessary modify, the Power Supply Charge to achieve no less than $25 million and no more than $125 million of earnings.

- In 2009 and 2010, the FPPCA rate was calculated to create a specific reduction in customer bills or a specified change in rates, as shown in **Exhibit 19-6**.

Exhibit 19-6
FPPCA Rate Drivers

Statement Number	Rate	Effective Date	Calculation Driver
21	10.3249	May 1, 2009	Decrease average bill 3.2 percent
22	9.9119	January 1, 2010	Decrease FPPCA rate 4.0 percent
23	9.3042	June 1, 2010	Decrease average bill 3.0 percent

Source: NorthStar review of Statement Calculations in DR 172

- Although there were rate reductions in 2009 and 2010, it is likely that if the change in FPPCA rate was calculated using updated fuel and purchased power cost projections, rather than specifying the desired outcome of the calculation, the rate would have been lower. However, the tariff in effect at that time only called for annual updates to cost projections. There was an over-collection in 2009 and 2010, as shown in **Exhibit 19-7**.

[20] DR 174

Exhibit 19-7
FPPCA Annual Over- and Under- Recovery Amounts
(Dollars in Millions)

Year	Over-Recovery	Under-Recovery
2009	$163.4	
2010	136.0	
2011	25.1	
2012		$43.1

Source: DR 456

19.3.8 The October 2012 changes to the FPPCA were approved by the Board following established approval guidelines.

- A draft resolution was provided to the Board prior to the October meeting.
- The proposed change to the FPPCA was accompanied by both memoranda and draft resolutions which described the proposed actions and explained the underlying rationale for the changes. The minutes of the October 25, 2012, Board meeting record a discussion of the FPPCA modifications and the subsequent Board action.

19.3.9 LIPA maintains sufficient historical financial records to assist with the verification of fuel and purchased power cost in the audit period.

- LIPA retains its records pursuant to the *Records Retention and Disposition Schedule MI-1*, issued by New York State Education Department. The retention schedule specifies a 6-year retention period for journal entries, invoices and purchase orders, and customer billing records.[21]
- LIPA was able to provide NorthStar with all requested documentation for its detailed transaction testing in 2012 and 2013.

19.4 Recommendations

19.4.1 Finalize the draft "Plan of Administration of Calculation of the FPPCA" and include better documentation concerning data flows, the calculation verification process and the responsibilities of the various organizations.

[21] DR 668

20. REGIONAL POWER MARKETS

This chapter reviews LIPA's involvement with the New York Independent System Operator (NYISO) and other regional power coordinating entities.

20.1 Background

As a participant in the Northeast wholesale energy markets, LIPA must comply with the rules and standards put forth by NYISO, the ISO New England (ISO-NE) and the Pennsylvania – New Jersey – Maryland Interconnection (PJM). LIPA must also comply with the rules of the New York State Reliabiliyt Council (NYSRC) and other reliability entities such as the Northeast Power Coordinating Council (NPCC) and the North American Electric Reliability Corporation (NERC). Each of these entities has stakeholder forums (such as standing committees, working groups, task forces and ad hoc groups) to address issues which may affect the reliability and cost of electricity for LIPA's customers.

- **NYISO** operates New York's high-voltage transmission network, administers and monitors New York's wholesale electricity markets, and plans for the state's energy future. NYISO has a shared governance structure. Market Participants, government officials and public interest groups work together in committees and working groups to forward market improvement recommendations to the Board of Directors. There are three standing committees: the Management Committee, the Business Issues Committee, and the Operating Committee. Each committee oversees its own set of working groups and/or subcommittees, and has a defined scope of responsibilities.

- **ISO-NE** is a regional transmission organization (RTO) serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. ISO-NE has many specialized committees and working groups to assist in the operation of New England's bulk power generation and transmission system and the power system planning process, including the Participants Committee & Working Groups, the Markets Committee & Working Groups, Reliability Committee & Working Groups, and the Transmission Committee & Working Group.

- **PJM** is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. An independent Board oversees PJM's activities. PJM's two senior committees are the Members Committee and the Markets and Reliability Committee. Other PJM committees monitor a specific task on a continuing basis. These committees report to the Senior Committees. There are three Standing Committees: the Market Implementation Committee, the Operating Committee, and the Planning Committee There are also additional committees which address specific areas, such as nominating and transmission expansion.

- **NYSRC** promotes and preserves the reliability of electric service on the New York State Power System by developing, maintaining, and updating the Reliability Rules for NYISO and all entities engaging in electric transmission, ancillary services, energy and power transactions on the New York State Power System. The NYSRC is governed by the NYSRC Executive Committee comprised of transmission owners (including LIPA) and other interested parties. The Executive Committee appoints three subcommittees: Reliability Rules Subcommittee; Reliability Compliance Monitoring Subcommittee; and Installed Capacity Subcommittee.

- **NPCC** is responsible for promoting and improving the reliability of the international, interconnected bulk power system in Northeastern North America. NPCC fulfills its reliability mission through committees, subcommittees, task forces and other groups as the Board of Directors may deem appropriate, including a Regional Standards Committee, a Compliance Committee, a Reliability Coordinating Committee (NPCC's principal technical committee), a Public Information Committee and an Audit and Finance Committee.

- **NERC** oversees eight regional reliability entities and encompasses all of the interconnected power systems of the contiguous United States, Canada and a portion of Baja California in Mexico. NERC has a complex committee structure which brings together hundreds of industry expert volunteers in nearly 50 committees, sub-committees, task forces, and working groups considering issues from wind and renewable power integration to education to demand-side management and energy efficiency.

20.2 Evaluative Criteria

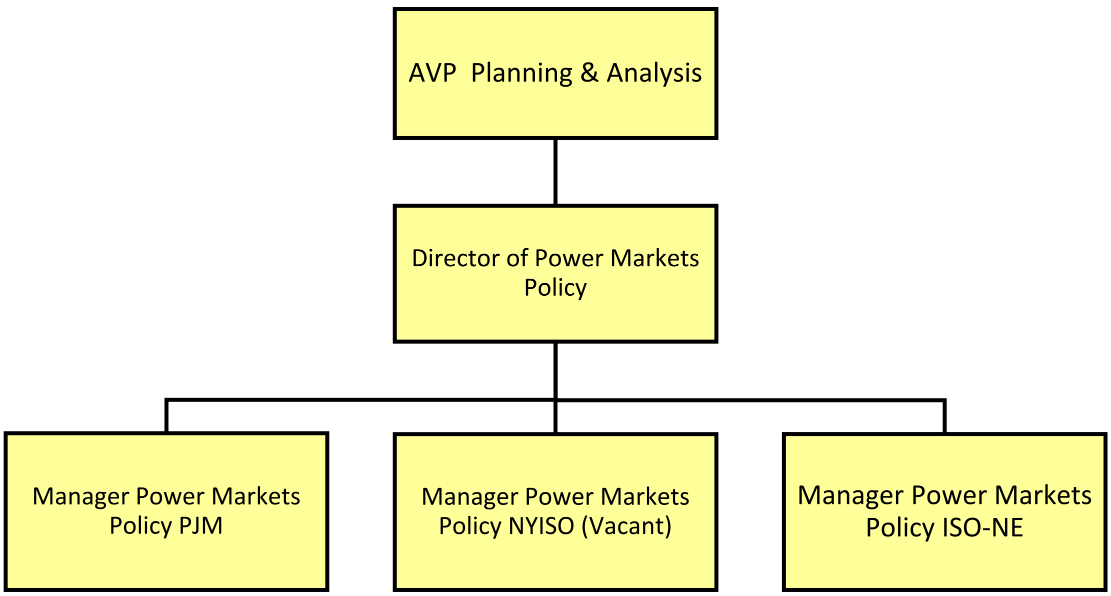
- Does LIPA have appropriate coverage at stakeholder forums in the relevant market/reliability entities in terms of number and expertise of both assigned personnel and management oversight, particularly in areas and emerging issues that are expected to have a significant impact?
- Does LIPA have adequate processes to identify emerging issues at the ISO/reliability entity level that may have a significant impact on its operations and its ratepayers?
- Does LIPA take appropriate actions to advocate for and protect customer interests and associated reliability and cost impacts in relevant stakeholder forums with respect to issues such as operations, billing, market rules; reliability rules, and results of planning studies?
- Does LIPA have adequate initiatives in developing and advocating changes in market and reliability rules in relevant stakeholder forums to help improve overall market efficiency and reliability?
- Does LIPA take adequate interest in improving the overall efficiency and effectiveness of state and regional market and reliability entities including, but not limited to, budgeting, and cost control, performance objectives and metrics, strategic planning and overall management?

20.3 Findings & Conclusions

20.3.1 LIPA has an effective organization to support LIPA's interests in the NYISO, PJM, and ISO-NE wholesale energy markets.

- LIPA's Power Markets Policy Group, under the Vice President for Power Markets is responsible for the Authority's participation in the NYISO, ISO-NE and the PJM wholesale electricity markets. As shown in Exhibit 20-1, this group reports to the Assistant Vice President of Planning and Analysis.

Exhibit 20-1
Power Markets Policy Organization



Source: LIPA Org Chart

- The Power Markets Policy group is comprised of a Director and three managers, and is receives support from National Grid and CEE, and other outside consultants.
  - The Director oversees LIPA's interests in the development of the market rules and systems in the Northeast ISOs in order to ensure that they are implemented in an efficient manner that both reduces LIPA's cost of power supply and supports the reliability of the LIPA system. He also serves as lead for LIPA at the NYISO, and coordinates LIPA participation in the Transmission Owners Committee.[1]
  - Each of the three Managers of Power Markets Policy is responsible for representing LIPA's interests in NYISO, PJM or ISO-NE wholesale energy market. The Manager represents LIPA on all of the necessary Committees, Task Forces, and Working Groups and is responsible for initiating and developing solutions to advance LIPA's causes both as a buyer and seller of energy, capacity, and services. The manager

[1] DR 344

works through the ISO committee processes and may work with legal counsel to defend LIPA's positions and where necessary protest NYISO positions that might be perceived to be discriminatory to LIPA's interests.[2]

  – National Grid and CEE represent LIPA on working groups and committees where they provide subject matter expertise.
  – With the current vacancy in the NYISO representative position, the PJM representative is also covering some NYISO meetings, and Power Markets Policy uses outside consultants to cover meetings when managers are not available, to the extent that the contractor costs do not exceed the cost of the vacant position.[3]

- The Power Markets Policy group also works closely with LIPA's Federal Energy Regulatory Commision (FERC) legal counsel and outside counsel since all of the ISO/RTO tariffs and market rules are subject to FERC jurisdiction.[4]

- Until the mid-2000's, LIPA used external consultants to represent its interests in the power markets. The decision to bring capabilities in-house was part of an effort to reduce reliance on consultants for on-going functions in order to reduce costs.[5]

20.3.2 LIPA is appropriately involved in tracking emerging market and reliability issues through the ISO and reliability entity stakeholder groups; a current vacancy has reduced the LIPA Staff attendance at stakeholder forums.

- LIPA tracks emerging market and reliability issues though direct engagement in the stakeholder processes of NYISO, ISO-NE and PJM. LIPA representatives, including LIPA employees and where appropriate LIPA contractors, sit on most committees and working groups at NYISO, and most major committees and working groups at ISO-NE and PJM. A key role of LIPA representatives in these committees and working groups is to consider which of the nearly one thousand issues raised each year impacts LIPA and warrants LIPA attention.[6]

- National Grid's Director of Load Forecasting currently chairs the NYISO Joint Task Force for Load Forecasting.

- Due to the current vacancy in the NYISO representative position, LIPA has increased its use of outside consultants to cover NYISO meetings. There has been some reduction in work performed by the Power Markets Policies staff.[7]

- The Power Markets Policy group, outside consultants, and representatives of some National Grid functions represented LIPA at over 200 meetings of 25 different NYISO

[2] DR 344
[3] IS 135
[4] DR 344
[5] IS 160
[6] DR 155
[7] IS 135

committees and working groups over a recent twelve month period, as summarized in **Exhibit 20-2**.

- LIPA Power Markets Policy representatives also attended 82 ISO-NE meeting and 149 PJM meetings in a one year period, as summarized in **Exhibits 20-3** and **20-4**. The LIPA representatives attend many of the meetings by phone or on-line.

Exhibit 20-2
LIPA Attendance at NYISO Meetings
10/1/2011 – 9/21/2012

Committee / Working Group / Task Force	Number of Meetings Attended by representatives from:				
	LIPA	Outside Consultant	LIPA and Others [1]	National Grid [2]	Total
Electric System Planning WG	19	2	3		24
Market Issues Working Group	13	6			19
Systems Operations Advisory Subcommittee				16	16
Operating Committee				13	13
Transmission Planning Advisory Subcommittee	11	2			13
Business Issues Committee	13				13
Installed Capacity Working Group	12				12
Billing and Accounting WG	9	3			12
Management Committee	12				12
Communication and Data Advisory Subcommittee				11	11
Load Forecasting Task Force				10	10
Budget & Priorities WG	9		1		10
Reactive Power Working Group				10	10
Inter-regional Planning Task Force /Electric System Planning WG		7	3		10
Installed Capacity WG/Price-Responsive Load WG	9				9
Other Meetings (10 different Working Groups)	22	5	1	1	29
Total	**129**	**25**	**7**	**60**	**223**

[1] LIPA Power Markets Policy personnel, plus consultant or National Grid representative.
[2] Representatives from National Grid's SCADA/EMS, Forecasting, Transmission System Control Center, System Planning/Transmission Planning, Protection & Telecom, and Transmission Operations & Compliance groups attended meetings related to their areas

Source: DR 154

Exhibit 20-3
LIPA Attendance at ISO-NE Meetings
10/1/2011 – 9/21/2012

Committee/Working Group	Number of Meetings		
	LIPA	Outside Consultant	Total
Forward Capacity Market Working Group	8	1	9
Markets Committee	14	2	16
Participants Committee	12	1	13
Planning Advisory Committee	11	1	12
Power Supply Planning Committee	4	1	5
Reliability Committee	12		12
Transmission Committee	13	2	15
Total	**74**	**8**	**82**

Source: DR 154

Exhibit 20-4
LIPA Attendance at PJM Meetings
10/1/2011 – 9/21/2012

Committee / Working Group / Task Force	LIPA
Regional Planning Process Task Force	17
Market Implementation Committee	15
System Restoration Strategy Task Force	13
Transmission Expansion Advisory Committee	12
Public Power Coalition	11
Planning Committee	10
Members Committee	10
Capacity Senior Task Force	8
Markets and Reliability Committee	8
Net Energy Metering Senior Task Force	7
MC Information Webinar	7
Other Meetings (21 total)	31
Total	**149**

Source: DR 154

- LIPA has an appropriate presence before the NYSRC.
  - National Grid represents LIPA at the Executive Committee, Installed Capacity Committee, and Reliability Compliance Monitoring/Rules Subcommittee meetings of the NYSRC.[8]

[8] DR 154

- LIPA's VP of Power Markets serves on the Executive Committee of the NYSRC with National Grid's Manager, System Planning as an alternate.[9]
- National Grid's Manager, System Planning, is a member of the Installed Capacity Committee.[10]

- LIPA is appropriately represented on numerous councils and committees at the NPCC as indicated in **Exhibit 20-5** (includes both present and recent past participants).

Exhibit 20-5
LIPA Participation at the NPCC

NPCC Member Representatives and Alternates	
LIPA	Director Power Markets Policy
National Grid	Director Network Strategy Planning
LIPA	AVP Planning and Analysis
LIPA	Director Planning and Analysis
LIPA	AVP Power Resources & Contract Management
LIPA	Manager of Power Markets Policy
LIPA	Director of Power & Fuel Operations
LIPA	Director of Risk Management
LIPA	AVP of Environmental Affairs
Reliability Coordinating Committee Members	
LIPA	Director Power Markets Policy
National Grid	Director Network Strategy Planning
National Grid	Resource Planning Section Manager
National Grid	System Planning Manager
LIPA	Director of Power & Fuel Operations
National Grid	Transmission Planning Section Manager
National Grid	Area Planning Section Manager
Task Force on System Protection	
National Grid	Manager Suffolk Protection
Task Force on Coordination of Planning (TFCP)	
National Grid	Transmission Planning Section Manager
National Grid	Transmission Planning Lead Engineer
SP-7 Working Group on Protection System Misoperation Review	
National Grid	Protection and Telecom

Source: DR 851

20.3.3 LIPA has effective processes to reflect the concerns of all LIPA organizations in its actions in stakeholder forums and to communicate relevant current issues at NYISO, NYSRC, NPCC and NERC to affected LIPA organizations.

- The Power Markets Policy group ISO representatives prepare written meeting notes and/or oral reports to bring issues salient to LIPA to the attention of the Director of Power Markets Policy for discussion, and, as appropriate, referral up to Senior Management.[11]

- The Power Markets Policy holds two weekly meetings: 1) an ISO Working Group meeting and, 2) a policy call.

[9] NYSRC Website
[10] NYSRC Website
[11] DR 154

- In the ISO Working Group meeting, stakeholders discuss the issues raised in the ISO committees, and the group considers the relevance of each issue to LIPA from a variety of perspectives. The group contains representatives from LIPA operations (National Grid), planning (LIPA and National Grid), policy (LIPA), and various LIPA consultants. [12]
- In the policy call, LIPA staff, counsel and contractors discuss salient issues identified in the stakeholder processes of NYISO, ISO-NE, PJM, NYSRC, NPCC and NERC policy, and how LIPA might take a proactive role in issues of LIPA interest. Progress on issues is tracked through the ISO stakeholder process and ultimately through various FERC processes.[13]

- Every other week, the LIPA Power Markets Policy and National Grid planning groups meet via teleconference to discuss the interaction of market issues and planning issues, including reliability standards where appropriate.
  - Issues requiring the attention of other functional units are highlighted and the issue is referred to that functional unit.
  - LIPA's Assistant Vice President of Planning and Analysis and National Grid staff participate in these meetings and coordinate issues via their membership in the Resource Planning Coordinating Committee and the Transmission and Distribution Planning Coordinating Committee.

- The AVP of Planning and Analysis communicates market policy issues in the monthly Power Supply Management meetings.

- The AVP of Planning and Analysis and Markets Policy staff also reviews active and salient issues with the Vice President of Power Markets in a monthly Status Update meeting. The Vice President of Power Markets briefs the LIPA Executive Team and LIPA BOT on issues warranting their attention.[14]

20.3.4 LIPA develops and advocates for changes in ISO energy markets that can impact the Authority's operations and the operations of the overall electric market.

- LIPA monitors the results of its participation in ISO committees and working groups, both in terms of the "key wins" on significant issues, and the estimated savings for LIPA operations. LIPA estimates that its efforts to address ISO issues from 2010 to 2012, combined with the overall actions of each ISO, will result in projected savings of $72 to $165 million annually over the next ten years.[15]

[12] DR 155
[13] DR 155
[14] DR 156
[15] DR 469 Confidential

20.4 Recommendations

20.4.1 Determine the impact of the current vacant position in the Power Markets Policy group on the achievements of the group at NYISO, and identify options for maintaining appropriate monitoring and participation in the NYISO and other regional power markets to protect LIPA's long-term power interests.

LIPA
Long Island Power Authority

September 20, 2013

Wayne Brindley
New York State
Department of Public Service
Three Empire State Plaza
Albany, NY 12223

Re: Matter No. 12-00314 – Comprehensive Management and Operations Audit of the Long Island Power Authority

Dear Mr. Brindley:

At the direction of the New York State Department of Public Service ("DPS"), NorthStar Consulting Group ("NorthStar"), completed a management and operations audit of the Long Island Power Authority ("LIPA") and submitted a draft report to DPS for review on July 30, 2013. After receiving feedback from DPS and fact verification from LIPA, NorthStar filed its Final Audit Report (the "Report") on September 13, 2013. In this regard, LIPA respectfully offers its comments on the Report.

Background

The Long Island Power Authority Oversight and Accountability Act (the "Oversight Act"), which was signed into Law on February 1, 2012, requires DPS to conduct periodic audits of LIPA's internal policies and procedures to improve the transparency and efficiency of its management and operations.[1] After a competitive procurement, DPS selected NorthStar to perform the audit, which was originally expected to commence in October 2012 and run through July 2013. However, due to Super Storm Sandy ("Sandy"), the audit was delayed and field work did not fully commence until April 2013.

As required by the Oversight Act, the audit addressed: 1) LIPA's construction and capital program planning in relation to the needs of its customers for reliable service; 2) the overall efficiency of LIPA's operations; 3) LIPA's Fuel and Purchased Power Cost Adjustment ("FPPCA") clause and recovery of costs associated with such clause; and 4) LIPA's annual budgeting procedures and process. Due to the schedule delay caused by Sandy, and the need to

[1] On July 29, 2013, the LIPA Reform Act (the "Reform Act") was enacted, which includes, among other things, the requirements of the LIPA Oversight Act, and provides for the next management and operations audit of LIPA (and its service provider) to commence in December 2015.

complete the audit as close to the original timeline as possible, DPS directed NorthStar to delete two topics from the audit scope: 1) the manner in which LIPA meets its debt service obligations; and 2) LIPA's compliance with debt covenants.

Given the scope and timing of the audit, it is important to note that the current organizational structure of LIPA, and its relationship with its service provider, is about to transition in a material way pursuant to the Reform Act. Currently, LIPA contracts with National Grid Electric Services, LLC ("National Grid"), pursuant to the Amended and Restated Management Services Agreement ("MSA"), to perform the day-to-day operations and maintenance of the transmission and distribution system ("T&D System"), including, among other functions, transmission and distribution facility operations, customer service, billing and collection, meter reading, financial and operational reporting, and planning, engineering and construction. LIPA exercises control over the performance of the T&D System through specific standards for performance contained in the MSA. In anticipation of the MSA's expiration on December 31, 2013, and following a competitive procurement process, LIPA entered into an Operating Service Agreement ("OSA") with PSEG Long Island LLC ("PSEG-LI") (a subsidiary of Public Service Enterprise Group) on December 28, 2011. Pursuant to the OSA, PSEG-LI would perform functions substantially similar to those performed under the MSA, commencing January 1, 2014, under a different organizational structure than currently exists. LIPA is currently engaged in revising the OSA to conform to the new requirements of the Reform Act, which further restructure the arrangement between LIPA and its service provider.

Notwithstanding the new law, given the timing of the audit, NorthStar focused predominately on LIPA's operations under the MSA model, the management and oversight of those operations exercised by the existing structure, and the OSA dated December 28, 2011. NorthStar's recommendations reflect areas where improvements are needed going forward, regardless of the scope of the services in the OSA or the structure of LIPA and its governing Board. The uniqueness of the timing of this audit, while contemplated under the Oversight Act, was exacerbated by the Reform Act, and thus, LIPA appreciates the need for the audit approach taken by NorthStar and believes that it led to findings and recommendations that can be a implemented over time, consistent with the impending new organizational structure at LIPA and contractual relationship between LIPA and PSEG-LI.

Audit Process

With the goals of the Oversight Act in mind, LIPA approached this audit as an opportunity to identify and assess those areas of its operations and management that need focus and improvement going forward. Throughout the course of the audit, DPS, NorthStar and LIPA (with support provided by National Grid and PSEG-LI), worked collaboratively to facilitate a comprehensive review of LIPA's operations and management. To that end, LIPA committed the necessary resources to facilitate the audit process and to ensure that LIPA was responsive to

NorthStar's requests. In total, LIPA responded to 908 data requests and 185 interview requests as part of the audit. LIPA appreciates that the Report recognizes that the audit was conducted in an open and constructive manner, including frank and meaningful discussions about NorthStar's findings, conclusions and recommendations.

Overall, LIPA believes that NorthStar's audit process was thorough and constructive. The collaborative efforts and discussions had between LIPA, DPS and NorthStar lead to a better understanding of the issues affecting LIPA and, in turn, strong and relevant recommendations aimed at improving operations going forward given LIPA's unique circumstances.

Key Findings and Conclusions

LIPA recognizes the importance of addressing the six cross-functional themes identified by NorthStar. LIPA acknowledges that these themes represent challenges that LIPA faces and is committed to more thoroughly understanding and addressing going forward. In this regard, LIPA acknowledges that addressing these areas is critical to LIPA improving overall performance, cost of service and customer service.

Notwithstanding the challenging environment in which LIPA exists, LIPA is committed to achieving excellent electric utility service for consumers. Accordingly, LIPA will refer back to the Report's six overarching themes as it is restructured pursuant to the LIPA Reform Act and as it transitions to and implements the proposed revised OSA. LIPA believes that these areas of concern can be addressed so as to allow LIPA, in conjunction with DPS, to achieve excellence in the provision of electric utility service for LIPA's customers. To that end, LIPA offers the following general comments in response to the six themes identified by NorthStar:

1. *A fully contracted utility operation such as LIPA, operating without a traditional command and control structure, is critically dependent on its "utility management IQ" to be successful.*
    - The change in structure called for in the Reform Act creates a more traditional "command and control" structure within LIPA's future service provider (PSEG-LI), which brings with it a greater "utility management IQ."
    - With respect to the LIPA Board of Trustees, the Reform Act has created minimum qualifications that the appointing authorities must consider when appointing members to the Board, namely "relevant utility, corporate board or financial experience." In this regard, the current Board has a significant amount of experience consistent with the Reform Act, including one Trustee with direct experience as an executive of similarly sized private and public utilities, and several other members with financial experience. The LIPA board has been serving during a period of significant challenges for the utility.
    - As the Report acknowledges, it is difficult for LIPA to attract and retain seasoned utility employees given various constraints identified in the Report; however,

LIPA has made significant strides in this area, including the addition of numerous, seasoned utility professionals to the management team, and will continue to build on its recent success in attracting and retaining experienced professionals in the future.

2. *As the entity ultimately responsible for electric service on Long Island, LIPA has to keep its contractors accountable for results – all the time. The service provider contract must drive performance, allowing LIPA to exercise its responsibilities as system owner and intervene as necessary to improve performance.*
    - The revised OSA, as contemplated, not only contains important performance metrics that will allow LIPA to keep PSEG-LI accountable for results related to reliability and customer satisfaction, but also requires the use of the PSEG-LI brand, which is a significant tool to create accountability on the part of LIPA's service provider.
    - Additionally, the new structure contemplated under the revised OSA provides for more transparency related to the provision of services in comparison to the MSA, including with respect to the cost of service. This transparency is viewed as a significant improvement that will enhance LIPA's ability to monitor and keep its future service provider, PSEG-LI, accountable.
    - LIPA will provide ongoing oversight of PSEG-LI operations and OSA performance. LIPA has other significant roles bearing on utility service including meeting utility financing needs, and, at least at the start of the process, policy development and resource planning.
    - DPS-Long Island will provide continuous guidance, diligent oversight and meaningful intervention as the proposed revised OSA is implemented going forward. DPS will be engaged in emergency planning and response, energy efficiency and renewables, capital budget review, OMS metrics review, rate cases, consumer complaints and other important areas.
3. *LIPA's customers deserve to be treated with maturity and respect, to receive accurate and timely information about system operations, rates and performance, and to have appropriate levels of service.*
    - One of the key strengths demonstrated by PSEG-LI during the procurement process leading to selection was PSEG's superior reputation in New Jersey, where it has a proven track record of 1st quartile customer service and reliability performance. In addition to numerous process improvements contemplated under the new contract, it should be noted that LIPA is currently working with PSEG-LI to implement a new Outage Management System, which is expected to provide for enhanced communication and restoration efforts related to storm events.
4. *LIPA cannot become subordinated to the service provider's core utility operations.*

- Within the framework of the revised OSA, PSEG-LI will operate as a ServCo unit dedicated to LIPA's operations, with PSEG-LI management primarily dedicated to LIPA's operations. LIPA believes that this will address weaknesses identified in the Report under the MSA framework and will lead to ongoing improvement in services and operations. LIPA operations and customers will be the primary focus of PSEG-LI employees and management.

5. *The Authority deserves to receive outstanding performance from its providers and should only pay premiums for performance above the current norms.*
    - The revised OSA metrics seek 1st quartile performance in both reliability and customer service. Additionally, LIPA expects that assistance from and oversight by DPS Long Island with respect to service received from PSEG-LI will enhance LIPA's ability to ensure that performance metrics meet the needs of the organization.
6. *Functional areas where LIPA is performing well should be preserved and supported through the transition to PSEG-LI and the ServCo model.*
    - LIPA expects the outcome of the new structure will result in the same high level of performance recognized in the Report, including the transfer of certain service contracts in the power markets area and the energy efficiency function to PSEG-LI and, shortly thereafter, the remainder of the power markets function.

Recommendations

In total, NorthStar offered 83 recommendations, including 43 recommendations that LIPA is able to adopt directly, and 40 recommendations that LIPA will seek to have PSEG-LI adopted and implement. While LIPA is preparing an implementation plan that would demonstrate how the 43 recommendations will be implemented, some general comments are offered as follows.

LIPA appreciates the effort and expertise that NorthStar provided during the audit process and in the development of these recommendations. In this regard, LIPA intends to work diligently to implement the recommendations with the assistance of DPS Long Island, and with the cooperation of PSEG-LI. With respect to recommendations that LIPA will seek to have PSEG-LI adopt, it should be noted that PSEG-LI has performed a preliminary review of the recommendations and has indicated to LIPA that a vast majority are already planned to be implemented in 2014.

Next Steps

LIPA believes that this audit was timely, productive and an important element of improving its operations going forward. As LIPA transitions from the MSA to the proposed revised OSA, the findings and recommendations in the Report will guide LIPA and its service providers (current and future) in improving operations now and in the future.

It is expected that NorthStar's recommendations will be presented to the LIPA Board of Trustees on October 3, 2013 for review and consideration. LIPA staff will recommend to the Board that the recommendations be accepted in full, with an implementation deadline of December 2015 (before the next management audit commences). Additionally, as the transition from National Grid to PSEG-LI continues, LIPA will work with PSEG-LI to help facilitate implementation of the recommendations in the Report applicable to them as service provider, consistent with the terms and conditions of the revised OSA.

LIPA appreciates and values NorthStar's and DPS's extraordinary efforts related to this inaugural management and operations audit of LIPA, particularly given the time and other constraints under which they were operating. The recommendations from NorthStar represent a sound framework for the types of changes contemplated by the LIPA Reform Act and the revised OSA, all of which are aimed at improving the quality of service to LIPA's customers. LIPA looks forward to continued collaboration with DPS and PSEG-LI to ensure their proper and efficient implementation.

Sincerely,

Lynda Nicolino
General Counsel and Secretary

cc: John D. McMahon, COO
LIPA Trustees

nationalgrid

John Bruckner
President
Long Island Electric T&D Services

September 20, 2013

Honorable Kathleen Burgess, Secretary
New York State Department of Public
Service
3 Empire State Plaza
Albany, New York 12223

Re: Case 12-00314 Comprehensive Management and Operations Audit of Long Island Power Authority

Dear Secretary Burgess:

National Grid welcomes this opportunity to submit the following comments in connection with the September 13, 2013 "Comprehensive Management and Operations Audit of Long Island Power Authority ("the Audit Report") Final Report prepared by NorthStar Consulting Group ("NorthStar") and submitted to the Public Service Commission ("Commission").

National Grid appreciates the hard work of those at NorthStar Consulting Group and the New York State Department of Public Service who worked diligently to gather and interpret the volumes of information associated with this Comprehensive Management and Operations Audit of the Long Island Power Authority. We openly recognize the challenge of collecting and analyzing this information, and the complexity of offering recommendations for improvement, especially during this period of change and transition of responsibility from National Grid to Public Service Electric and Gas - Long Island, llc.

National Grid is also proud of the service it has and continues to provide to LIPA and the customers that we serve on their behalf and are especially thankful for the efforts of our employees who not only supported this audit, but who have selflessly served the customers of Long Island for the past 15+ years. We remain committed to providing this same level of focused attention through the term of our contract which expires at year's end and to supporting ongoing efforts to enable a smooth and successful transition.

While the audit report is comprehensive, there are however, several areas where National Grid believes additional information would help to further clarify the audit findings and offers the following statements:

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1. Throughout the term of the MSA Contract, National Grid has provided a high level of management attention to LIPA, having a dedicated staff and management team on Long Island solely devoted to LIPA's business. In executing this contract, this management team and its employees were greatly focused on continuous improvement of the business. Nevertheless, National Grid's Long Island operations did not always benefit from the implementation of tools and processes utilized in other parts of National Grid's NYS electric operations. In many cases, LIPA's desire to remain independent from National Grid operations often precluded our adoption of or participation in such initiatives on Long Island.

2. As a means to further enhance the quality of service, National Grid has and continues to welcome the auditing of its functions and processes engaged in the delivery of its contracted services to LIPA. In fact, National Grid not only fully cooperated in the current Department of Public Service Management Audit, but at LIPA's request engaged its own Internal Audit team to perform approximately 20 independent audits on various aspects of its business for them since January 2010. Results from such audits were openly shared with LIPA and provided the basis for many National Grid service enhancement initiatives.

Overall, National Grid found this audit process to be a collaborative and constructive, identifying performance areas of strength as well as opportunities for improvement that should benefit LIPA's customers in the future. While not inclusive of all clarifications, we trust that our above comments will provide additional value in interpreting information contained in the Audit Report.

Sincerely,

John Bruckner
President, Long Island Jurisdiction

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