LIPA
Long Island Power Authority

PSEG LONG ISLAND

June 29, 2018

Mr. Ralph V. Suozzi, Chairman
Long Island Power Authority
333 Earle Ovington Boulevard
Uniondale, New York 11553

John B. Rhodes, Chief Executive Officer
Department of Public Service
Three Empire State Plaza
Albany, New York 12223

Re: Matter No. 16-01248 - Comprehensive Management and Operations Audit of the Long Island Power Authority and PSEG Long Island

Dear Chairman Suozzi and Chief Executive Rhodes:

The Department of Public Service ("DPS") and its consultant, NorthStar Consulting Group ("NorthStar"), have submitted a management and operations audit of the Long Island Power Authority and PSEG Long Island for review by the Board of Trustees at its meeting on Wednesday, July 25, 2018.

Since the audit began 18 months ago, LIPA's staff and PSEG Long Island have collaborated to provide access to the personnel and data requested by NorthStar. The audit examined 14 areas of management, oversight and operations:

- Progress on Implementing the 2013 Audit's Recommendations,
- LIPA Executive Management and Governance,
- Enterprise Risk Management,
- Budgeting and Financial Reporting,
- Debt Management,
- Load Forecasting,
- System Planning and Distributed Platform Development,

- Transmission and Distribution,
- Program and Project Planning and Management,
- Work Management and Outside Services,
- Customer Operations,
- External Outreach and Communications,
- Performance Management,
- Fuel and Purchased Power, and
- Pension and OPEBs.

Together, LIPA and PSEG Long Island answered over 1,000 data requests and provided over 5,000 supporting documents, totaling 9.5 gigabytes of data. NorthStar and DPS staff conducted 222 interviews with LIPA Trustees and staff and PSEG Long Island. These statistics convey to you the thoroughness and professionalism of the DPS and NorthStar audit team and the audit process.

The audit report recognizes the strides both LIPA and PSEG Long Island have made since passage of the LIPA Reform Act in 2013. The report states PSEG Long Island's "significant investments in customer service… are showing results" and credits "LIPA's exceptional financial leadership… for many noteworthy accomplishments," including saving customers over $490 million dollars.

NorthStar and other third parties have objectively recognized our accomplishments over the last four years, including:

- PSEG Long Island's ranking as the most improved utility in the nation for customer satisfaction since 2013 according to J.D. Power;
- Moody's Investors Service upgrade of LIPA's bond rating for the first time in 11 years in 2016, and Standard and Poor's upgrade of LIPA to "positive outlook" in 2017;

- PSEG Long Island's recent recognition by the American Public Power Association for its commitments to reliability, safety, and infrastructure improvements; and
- NorthStar's finding that PSEG Long Island has maintained high levels of reliability when compared to other New York utilities. PSEG Long Island customers have the second lowest number of outages annually and the shortest outage durations in New York.

However, successful organizations must continue to do better every day. In addition to reflecting our accomplishments, the NorthStar review provides numerous insights that will help LIPA and PSEG Long Island to further enhance customer service, reliability and accountability for our customers.

In several areas, NorthStar's findings encourage improvements already underway. For instance, NorthStar recommends LIPA and PSEG Long Island "continue" or "build on" successes in enterprise risk management, vegetation management, and the use of performance incentive metrics to drive continuous improvements and achieve industry best practices. NorthStar has also identified new opportunities to enhance our performance.

Pursuant to the LIPA Reform Act, the Trustees must review the audit's findings within thirty days of receipt for consistency with sound fiscal operating practices, any existing contractual or operating obligation, or the provision of safe and adequate service. Unless the Board makes a preliminary finding of inconsistency with respect to any such finding or recommendation, the LIPA staff and PSEG Long Island will develop specific project plans to implement each of the NorthStar audit's recommendations.

A meeting of the Board has been scheduled for July 25 to provide the Trustees with the opportunity to review the audit's recommendations within the thirty-day statutory deadline. LIPA staff and PSEG Long Island are available to provide additional information to individual

Trustees regarding any questions you may have on the audit findings leading up to the July Board meeting.

After that meeting, the Board's Policy on Audit Relationships provides for LIPA staff and PSEG Long Island to periodically report to the Trustees on our progress addressing each audit recommendation.

Regular independent audits of the management and operations of complex organizations are valuable. We appreciate the hard work of the DPS staff and the NorthStar team whose recommendations will contribute to the continuous improvement of our utility. We also wish to commend the efforts of the LIPA and PSEG staff, both for their many achievements over the last four years and for the thousands of hours devoted to making this audit a success.

The efforts we now undertake will continue the mission of the LIPA Board to "enable clean, reliable and affordable electric service for our customers on Long Island and the Rockaways."

Sincerely,

Thomas Falcone

Thomas Falcone
Chief Executive Officer
Long Island Power Authority

Daniel Eichhorn
President and Chief Operating Officer
PSEG Long Island

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John B. Rhodes
Chair and
Chief Executive Officer

Thomas Congdon
Deputy Chair and
Executive Deputy

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Paul Agresta
General Counsel
Kathleen H. Burgess
Secretary

June 29, 2018

Sent Electronically and via US Mail

Honorable Ralph V. Suozzi, Chairman
Board of Trustees
Long Island Power Authority
333 Earle Ovington Blvd.
Uniondale, New York 11553

Re: Matter No. 16-01248 – In the Matter of a Comprehensive and Regular Management and Operations Audit of Long Island Power Authority and PSEG Long Island LLC.

Dear Chairman Suozzi:

In accordance with Public Service Law (PSL) §3-b(3)(d) and Public Authority Law (PAL) §1020-f(bb)(2), the New York State Department of Public Service (the Department) has completed the Comprehensive and Regular Management and Operations Audit of Long Island Power Authority (LIPA or the Authority) and its Service Provider, PSEG Long Island LLC (PSEG LI). The Final Audit Report is provided electronically herewith to the Board of Trustees and will simultaneously be posted on the Department's Document and Matter Management System (DMM), accessible through the Department's website.

The audit was performed in accordance with PSL §3-b(3)(d) and PAL §1020-f(bb). PSL §3-b(3)(d) authorizes the Department to conduct periodic audits of LIPA and its Service Provider. PAL §1020-f(bb)(2) requires that LIPA and its Service Provider cooperate with the Department in the undertaking of periodic audits, and specifies that the audit include but not be limited to an analysis of the following: (i) the Service Provider'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 and its Service Provider'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 and its Service Provider's annual budgeting procedures and process; (vi) the application, if any, of the performance metrics designated in the Amended & Restated Operations Service Agreement and the accuracy of the data relied upon with respect to such applications; and (vii) the Authority's compliance with debt covenants. Additional scope areas defined by this audit included (viii) Corporate Governance and (ix) the implementation of the recommendations from the Department's Comprehensive Management and Operations Audit of LIPA in Matter No.12-00314.

PSL §3-b(3)(d) affords the Department the discretion to have the audit conducted by an independent contractor. After a competitive procurement process, the Department selected NorthStar Consulting Group, Inc., to perform the audit.

In accordance with PAL §1020-f(bb)(3), LIPA and PSEG LI are required to post the Final Audit Report, including findings and recommendations, on their website. Unless the LIPA Board of Trustees makes a preliminary determination, within 30 days, that any particular finding or recommendation contained in such audit is inconsistent with LIPA's fiscal operating practices, any existing contractual or operating obligation, or the provision for safe and adequate service, the Board of Trustees and LIPA shall implement or cause its Service Provider to implement such findings and recommendations in accordance with the audit.

Sincerely,

John B. Rhodes
Chief Executive Officer

cc: Thomas Falcone, LIPA, CEO
Jon Mostel, LIPA, Secretary
Dan Eichhorn, PSEG LI, CEO
Guy Mazza, DPS LIO, Director

Attachment

COMPREHENSIVE AND REGULAR MANAGEMENT AND OPERATIONS AUDIT OF LONG ISLAND POWER AUTHORITY AND PSEG LONG ISLAND, LLC

MATTER NO. 16-01248

FINAL REPORT

Submitted to the:

Department of Public Service

Three Empire State Plaza
Albany, NY 12223-1350

JUNE 29, 2018

NORTHSTAR CONSULTING GROUP
MANAGEMENT CONSULTANTS

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I. 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) and PSEG Long Island LLC (PSEG LI) pursuant to Matter No. 16-01248.[1] This chapter of our report provides an executive summary of our findings and recommendations. The chapter includes a discussion of broad themes that cross over many functional areas and are of critical importance for LIPA and its Service Provider – PSEG LI in a section titled – Overview of Audit Findings and Conclusions.

A. LIPA BACKGROUND

LIPA is a New York Public Authority that owns the electric transmission and distribution (T&D) system on Long Island, New York. LIPA provides electric service to approximately 1.1 million customers in Nassau and Suffolk Counties and on the Rockaway Peninsula in Queens on Long Island. LIPA acquired responsibility for electric services on Long Island in 1998. At that time, LIPA acquired the electric transmission and distribution assets of Long Island Lighting Company (LILCO), KeySpan Corporation acquired LILCO's natural gas distributions assets, and LILCO's electric generating assets on Long Island. **Exhibit I-1** provides an overview of the service territory. LIPA does not provide natural gas service or own any on-island generating assets.

Following a Request for Quotation (RFQ)/Request for Proposal (RFP) process, LIPA entered into an Operations Services Agreement (OSA) on December 28, 2011 with Public Services Enterprise Group, Inc. (PSEG), to manage the operations of LIPA's T&D system, starting January 1, 2014. Effective January 1, 2014, the Authority's role significantly changed as a result of the LIPA Reform Act of 2013 (LRA). Part A of the LRA addresses the reorganization of the Authority and substantially changes its operating responsibilities. Under the Authority's new business model, PSEG LI, a wholly owned subsidiary of PSEG, manages the operation of the electric T&D system through an Amended and Restated OSA (A&R OSA).

LIPA is governed by a Board of Trustees (BOT or Board) consisting of nine members appointed by the Governor, the President of the Senate, and the Speaker of the Assembly. LIPA must obtain approval from the New York State (NYS) Comptroller's Office for contracts in excess of $50,000. LIPA is also subject to the State Administrative Procedure Act, the Public Authorities Law, the State Finance Law, and various NYS Executive Orders.

PSEG LI is fully dedicated to the Authority's operations and provides operations, maintenance and related services for the T&D system. The A&R OSA conforms to the LRA, which shifted the major operational responsibilities for the T&D system, including

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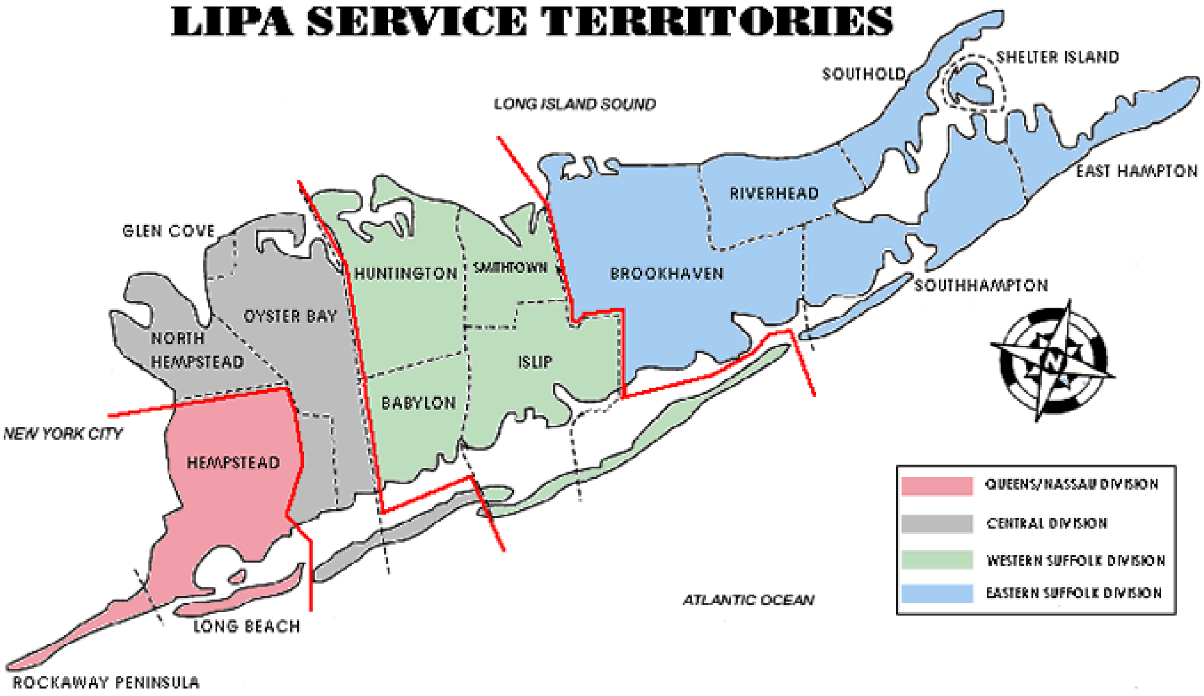
[1] Another PSEG subsidiary is the regulated utility in New Jersey – Public Service Electric & Gas (PSE&G)

significant responsibilities relating to capital expenditures and emergency response, from the Authority to PSEG LI. Essentially all costs of operating and maintaining the Authority's T&D system incurred by PSEG LI are paid by the Authority. PSEG LI is paid a management fee and may earn incentives related to specified performance metrics. The A&R OSA has a term of 12 years expiring on December 31, 2025, with a provision allowing for an eight-year extension.

Exhibit I-1



B. AUDIT APPROACH

This management and operations audit provides a unique opportunity to gain valuable insight into LIPA's and PSEG LI 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 and PSEG LI's executive management, construction program planning, system operations, financial management, customer operations, fuel and purchased power and provides recommendations for performance improvements.

Scope, Objectives and Audit Timetable

The audit was performed in accordance with the LRA through its revision of the Public Service Law (PSL) §3-b(3)(d) and the Public Authority Law (PAL) §1020-f(bb). PSL §3-b(3)(d) affords the Department the discretion to have such audit conducted by an independent auditor chosen by and under terms negotiated by the Department, through a contract entered into between the independent auditor, LIPA, and the Department. The process used by the Department to select the independent auditor is similar to the process it currently uses pursuant to PSL §66(19), as applied to audits of investor-owned utilities. The LRA 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.

As indicated in the DPS Request for Proposal, NorthStar's audit proposal and the Final Approved Work Plan, the audit scope is comprehensive, focusing on LIPA's operations and management as performed by PSEG LI, 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,[2] the audit addresses:

- The Service Provider's construction and capital program planning in relation to the needs of its customers for reliable service;
- The overall efficiency of the Authority's and its Service Provider's operations;
- The manner in which the Authority is meeting its debt service obligations;
- The Authority's Fuel and Purchased Power Cost Adjustment clause and recovery of costs associated with such clause;
- The Authority's and its Service Provider's annual budgeting procedures and process;
- The application, if any, of the performance metrics designated in the A&R OSA and the accuracy of the data relied upon with respect to such application;
- The Authority's compliance with debt covenants;
- Corporate Governance; and
- The implementation of the recommendations from the Department's Comprehensive Management and Operations Audit of LIPA in Matter No. 12-00314.

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
- 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, and additional recommended evaluative criteria. We examined operating conditions as they existed, with significant focus on how LIPA provides oversight

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

of PSEG LI. The audit identified and addressed gaps and recommended improvement opportunities that will benefit LIPA's ratepayers as the management relationship with PSEG LI continues.

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 managers, LIPA, and PSEG LI throughout the engagement.

The RFP and proposal identified a time schedule for the audit assuming a start date of February 2017, submission of a draft report in March 2018 and final report on or before June 15, 2018.

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's 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.

- Completed logistical and contractual arrangements with DPS Staff, LIPA, and PSEG LI. 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.

- Met with DPS Staff to discuss any additional areas of inquiry regarding LIPA and PSEG LI, 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 included detailed evaluative criteria; tasks, activities, consultant assignments and hours; and a revised audit schedule. It was submitted May 23, 2017, and approved in early August 2017.

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 and PSEG LI.
- Interviews with LIPA, PSEG LI, and other appropriate personnel.
- Testing compliance with Authority, industry, and other standards.

NorthStar's audit activities included 1,007 information requests representing approximately 5,000 documents and 220 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 and PSEG LI are 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 managers for review and comment on February 2, 2018. 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. Taking into account feedback from the DPS Staff and fact verification by LIPA and PSEG LI, NorthStar prepared a Final Report.

Organization of the Report

This report is comprised of 15 chapters, including the Executive Summary – this chapter that includes an overview of NorthStar's approach to the audit.

Chapter II – Background on LIPA and Prior Audit Recommendations 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 and provides a recap of the audit recommendations from 2013 along with the status of their implementation.

Alignment of the DPS audit scope contained in its RFP with technical chapters of this report is shown in **Exhibit I-2**.

Exhibit I-2
Audit Scope Elements and Report Chapters

C1 – Construction and Capital Program Planning

C1.1: Enterprise Risk Management (ERM)	Chapter IV
C1.2: PSEG LI's System Planning and DSP Development	Chapter VII
C1.2.a: Decision Making	
C1.2.b: Management and Organization Structure	
C1.2.c: System Design and Capabilities	
C1.3: Program and Project Planning and Management	Chapter IX
C1.4: Performance and Results Management	
C1.5: Transmission and Distribution	Chapter VIII
C1.5.a: Reliability	
C1.5.b: Preventive Maintenance	
C1.5.c: Repair/Replace and Maintenance	
C1.5.d: Outage Management – System Improvement and Perf	
C1.6: Load Forecasting	Chapter VII

C2 – Efficiency of LIPA's and PSEG LI's Operations

C2.1: Work Management	Chapter X
C2.2: Effectiveness of Reporting Financial Information	Chapter V
C2.3: Customer Services	Chapter XI
C2.3.a: Customer Complaints	
C2.3.b: Customer Support Systems and Billing	
C2.4: Customer Call Center and Operations	
C2.4.a: Call Center – System Improvement and Perf	
C2.4.b: Customer Operations	
C2.5: Customer Outreach and Communications	Chapter XII
C2.6: Outside Services	Chapter X

C3 – Meeting Debt Service Obligations

C3.1: Application of Industry Standards to Manage Debt	Chapter VI
C3.2: Receipt of Necessary Approvals for Debt Management	
C3.3: Audit of Debt Management Practices	
C3.4: Effectiveness of Risk Management Techniques	
C3.5: Debt Management and Meeting Debt Obligations	
C3.6: Shoreham Acquisition Adjustment and Subsequent Changes	
C3.7: Cash Reserve Policy	

C4 – Fuel and Purchased Power Cost Adjustment and Cost Recovery

C4.1: PSEG LI's Involvement in NYISO Issues	Chapter XIV
C4.2: Fuel and Purchased Power Contract Management	
C4.3: PSEG LI's Supply Procurement	
C4.4: Fuel and Purchased Power Tariff Leaf 166	
C4.5: Fuel and Purchased Power Cost Recovery	

C5 – Annual Budgeting Procedures and Process

C5.1: Capital and O&M Budgeting	Chapter V
C5.2: PSEG LI's Budget Control	

C6 – Performance Metrics and Accuracy of the Data

C6.1: PSEG LI's Data Collection	Chapter XIII
C6.2: Metric Calculation	
C6.3: Modification/addition of new metrics	

C7 – The Authority's Compliance with Debt Covenants

C7.1: Compliance with all Debt Covenants	Chapter VI
C7.2: Management of Debt Covenant Requirements	

C8 – Corporate Governance

C8.1: Executive Management	Chapter III
C8.2: Current and Future Organizational Structure	
C8.3: LIPA's Board of Trustees (Board)	
C8.4: Communication and Control	Chapter III
C8.5: Strategic Planning	
C8.6: Pension and OPEB Investments	Chapter XV

C9 – Implementation of Audit Recommendations

C9.1: Recommendations Implementation Evaluation	Chapter II

Overview of Audit Findings and Conclusions

LIPA faces extraordinary 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 $7 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 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 relatively high when compared to average New York electric rates.[3] Recognizing this difference, the LIPA Board adopted a policy whereby LIPA seeks to remain competitive with the electric rates of other utilities serving the New York metropolitan area. LIPA historically suffered from poor customer satisfaction, previously falling to the bottom of the JD Power annual survey. Many of these issues have been faced head-on by LIPA and PSEG LI with remarkable achievements.

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. PSEG LI has made significant investments in customer service, which are showing results.

Under the terms of the A&R OSA, PSEG LI earns incentive compensation for achieving several performance metrics. As these are heavily weighted towards customer satisfaction, PSEG LI has a strong incentive to improve customer service levels and has done so. Customer satisfaction as measured by JD Power surveys has risen. With the 2018 Wave 1 residential survey, PSEG LI was no longer in the fourth quartile in residential customer satisfaction ranking, tying for 10th place amongst the 16 East Large Utilities. Customer satisfaction with the call center has risen dramatically, and, as a result, the residential and non-residential after call survey metrics have been dropped from improvement to maintenance metrics. These are customers that have had actual contact with the utility, while JD Power survey respondents may not have had any recent contact with the utility. Customer satisfaction with the customer offices, electric field representatives, major account executives, and callers to the energy efficiency hotline has shown notable improvement; however, customers still report frustration with LIPA's rates. PSEG LI has implemented process and technology changes to improve customer service. Customers are able to communicate with the utility and manage their accounts using a variety of technologies.

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[3] https://www.nyserda.ny.gov/Researchers-and-Policymakers/Energy-Prices/Electricity/Monthly-Avg-Electricity-Residential

2. LIPA's exceptional financial leadership has resulted in many noteworthy accomplishments.

LIPA is responsible for managing the debt issuance process and providing capital to fund the utility's capital program. LIPA's Chief Financial Officer (CFO) has responsibility for the debt issuance process, with support from personnel both inside and outside LIPA. LIPA's utility plant totals $7.8 billion and long-term debt at December 31, 2016 was $7.8 billion including Utility Debt Securitization Authority (UDSA) debt of $4.0 billion.

- As part of its decision to implement a Three-Year Rate Recommendation, the LIPA Board adopted a new financial policy on December 15, 2015, with several key components.
    - Adoption of the Public Power Model – The Public Power Model, used by nearly all of the country's major public power providers, recovers LIPA's operating expenses plus its debt service requirements.[4]
    - Adoption of Mid-A Ratings Target Over Five Years – LIPA adopted a five-year plan to improve its credit ratings to A2/A/A.[5]
    - Reduce Borrowings to No More than 60-64 Percent of Capital Spending – LIPA's debt ratio (defined as debt as a percentage of the net physical assets of the electric system plus working capital) is higher than the average utility. LIPA plans to reduce borrowings in each year to no more than 60 to 64 percent of capital spending, with the balance funded by cash flow from operations.[6]
    - Increasing Fixed Obligation Coverage Targets – To achieve the goals of improved credit ratings and reduced borrowings over five years, LIPA adopted fixed obligation coverage targets that increase each year.

- The LRA's Securitization Law created the Utility Debt Securitization Authority (UDSA) in 2013 (Part B of Chapter 173, Laws of New York State). Its sole mission is to authorize, issue and sell restructuring bonds, and to pay the financing costs, interest and principal on these bonds.[7] The proceeds from these bond sales are used to pay off outstanding LIPA bonds, which have much higher interest rates. UDSA debt is rated "AAA" by the major rating agencies, and results in a lower cost of funds than the lower-rated LIPA debt.

- LIPA generated over $186 million of savings for customers from refinancing $1.5 billion of LIPA and Utility Debt Securitization Authority bonds during 2016. During 2017

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[4] DR 14 Attachment 163

[5] DR 14 Attachment 163

[6] DR 14 Attachment 163

[7] http://www.lipower.org/UDSA/docs/MissionStatement.pdf

UDSA bonds provided another $45 million. Total savings for all the UDSA bonds total $491 million.[8]

3. Effective oversight is critical when contracting virtually all utility operations and maintenance.

Traditional utilities make decisions at the top of their organizational structure – decisions which are then communicated down their chain of command and implemented. Utility managers base decisions on analysis, current information, and past experience focused exclusively on the mission of one entity – their *own* utility company.

In contrast, LIPA is separated from daily utility operations, information and experience by a formal contract with its service provider – PSEG LI. For a utility operating with this business model, the need for strong management skills and a deep understanding of the nuances of utility operations is critical to provide effective oversight and continuous improvement.

- LIPA's organization structure is suitably aligned with its mission; however, staffing levels limit its ability to oversee operational activities in greater detail.

- LIPA oversees PSEG LI's spending (both capital and O&M). Going forward, LIPA and PSEG LI must strive for greater efficiencies.

    - To date, capital project cost overruns were met by deferring another project to stay within budgets.
    - PSEG LI recognizes that capital project estimates must be improved and has launched a program to rectify the problem along with related project management controls.

- Improvements in T&D construction, maintenance and operation will require the explicit definition and quantification of work standards.

4. LIPA has to drive performance improvement while staying within the scope provisions of the A&R OSA.

In its review of the A&R OSA, the DPS recognized that it was critical that Long Island utility customers receive electric service that is both cost-effective and is of the high quality that is comparable to what is demanded of other New York utilities and by PSEG's New Jersey regulators and customers. The Amended OSA expanded PSEG LI's role to allow it to effectively assume its management responsibility, and increased the level of both fixed and incentive compensation. The DPS further recognized that one of the critical features of the A&R OSA is the establishment of clear metrics that provide a transparent mechanism for the BOT, the Department and other stakeholders to ensure that agreed to financial and

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[8] http://www.lipower.org/pdfs/company/trans/2016/Discussion%20of%202016%20Goals%20and%20Accomplishments.pdf

operational performance measures are met. The Department considered the measures in their totality to be a good starting point for operations, but acknowledged that the A&R OSA contemplates that the metrics will be reviewed and changed in order to ensure continuous operations improvement.[9]

In general, the initial targets were designed to produce generally first quartile performance, or substantial improvements from 2013 baseline performance, generally by year five. PSEG LI is able to earn a multiplier of the base points for improvement metrics if targets are achieved before year five.

While the A&R OSA performance metrics are not the only means available to LIPA to evaluate PSEG LI's performance, they are a significant behavioral driver. PSEG LI has generally met or exceeded its incentive metrics since it took over as service provider in 2014. Under the terms of the A&R OSA, both parties must agree to revisions to the metrics.[10] Any revisions to the metrics, targets, weightings or tiers is the result of a negotiated process. While there have been changes to the metrics and targets over time, LIPA and PSEG LI should continue to evaluate how to best incent service provider performance, drive continuous improvement and align the metrics with the focus of LIPA and PSEG LI's long-term strategy and operational needs.

5. **The LIPA Board has improved since the LRA, but faces the dilemma most boards of public power agencies face: how to increase the level of utility or energy industry experience commensurate with an organization of LIPA's size, complexity and revenues.**

- Typical practice for a Board composition 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. The LRA recognizes the importance of Board composition by requiring all board members to have expertise in the following areas: relevant utility, corporate board or financial experience.

- Materials provided to the Board are numerous, complex and require insightful understanding of utility issues. Offsetting these factors are the facts that many documents contain only minor changes from earlier versions and that some documents relate only to members of certain committees. Responses to NorthStar's data requests show that over 750 documents including formal reports, meeting minutes and updates were provided to the Board from 2014 through 2016. This translates into more than 40 documents to be reviewed by Board members for each Board meeting.[11] These levels underscore the need for Board members to be committed to a heavy workload.

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[9] LIPA/PSEG LI Fact Verification.

[10] DR 4 A&R OSA Appendix 9, pp. 7-8

[11] DRs 13, 14, 16 and 411

- The Board's level of involvement in decision making is focused on oversight and approval. The Board should consider what is the suitable level of involvement and leadership for it to provide to LIPA. The Board has recently adopted a number of formal policies to define its purpose and role, relying on LIPA staff for their development.

- The degree to which the Board exercises authority and responsibility may be measured in part by its activity level. LIPA's Board activity is comparable to other public boards, but is relatively low compared to boards of large investor-owned utilities.

- The Authority utilizes the Consent Agenda thereby shortening the duration of the full Board meeting and focusing the discussion agenda on those items most warranting discussion. Any individual Board member has the ability to move items from the Consent Agenda to a full discussion. Consent items are part of the full board agenda and the public has the opportunity to speak on consent items. During the course of meetings observed by NorthStar some significant policy issues and substantive decisions were addressed as Consent Items.[12]

- Certain Trustees continue although their terms of service have officially expired. At the time of the audit, three of the Trustees were continuing to serve although their terms had expired and three more had terms that expired at the end of 2017.[13]

C. SUMMARY OF RECOMMENDATIONS

This report contains a total of 49 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 and PSEG LI's operations under the A&R OSA model, the management and oversight of those operations exercised by the existing LIPA structure and personnel. We have focused our recommendations in areas where improvements are needed going forward.

LIPA's and PSEG LI'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 to the service provider, PSEG LI should consider these recommendations for improvement in the same light.

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[12] NorthStar Analysis

[13] DR 987

Exhibit I-3
Summary of Audit Recommendations

LIPA Background and Prior Audit	
1	LIPA and PSEG LI should work with the DPS to determine which of the outstanding recommendations from the 2013 are still relevant and should be implemented.
2	LIPA and PSEG LI should develop an implementation plan for all audit recommendations (new recommendations and outstanding recommendations that LIPA, PSEG LI and DPS determine remain relevant) within 90 days of the Final Audit Report acceptance and submit the implementation plan to the LIPA Board of Trustees and the DPS. The Report could take the form required of the IOUs
3	LIPA Internal Audit should perform a comprehensive audit of the implementation status of all audit recommendations annually until the next DPS audit is performed. The results of LIPA's audit should be submitted to LIPA executive management, the LIPA Board of Trustees, PSEG LI, and the DPS. Within each LIPA audit: • An evaluation of progress performance should be included. • A progress tracking document should show activities completed to date and those in process. • Any revisions to completion targets should be highlighted for management review.
Executive Management and Governance	
4	LIPA Financial Oversight should formally document the results of its PSEG LI oversight activities and assessment process annually with submission to LIPA/PSEG LI executive management as well as DPS,
5	LIPA should formally request appointments or confirm extensions to Board member term periods at least six months prior to term expirations.
ERM	
6	LIPA and PSEG LI should continue to develop an effective, comprehensive ERM process.
Budgeting and Financial Reporting	
7	Continue to develop and implement the SOS capital program optimization model. • Implement improvements identified by PSEG LI and LIPA Internal Audit, including: - Review and adjust the project description questions. • Add a demographic category for "permitting required", which can act as a flag of sorts when running optimization scenarios. • Flag projects that are necessary to remediate a violation or to prevent a violation. - Review the scoring criteria for each business area when setting up a new project in SOS. - Identify any biases toward certain types of projects. - Refine the Strategic Objectives and the Success Criteria. Consider including Success Criteria not used for the 2018 budget, such as NPV and the financial risk of deferral. • Expand the use of SOS to other business areas, including IT and Customer Operations. • Include a step in the SOS optimization process to calibrate value and risk scoring across business units that develop capital projects such as Network Strategy Planning group, Electric Operations, and Reliability Management. IDA should lead a process to review the scoring of projects with similar risk values to ensure the projects are scored on a comparable basis. Similarly, IDA should ensure the different organizations use comparable bases for value scoring the projects using the Strategic Objectives and the Success Criteria.
8	Provide LIPA-specific capital budget versus actual expenditure variance data to the BOT in each F&A Committee package.
9	Update the PSEG LI budget procedure to include the determination of incremental O&M expenses associated with new construction.
10	Complete the process of upgrading LIPA's financial system.
11	Determine the feasibility and cost of establishing interfaces between PSEG LI's MicroStrategy, PCM, and SAP systems to eliminate the need for manual data transfer processes. If cost effective, implement processes to allow electronic data transfer between the systems.
Debt Management	
12	LIPA should build on its recent success in "homogenizing" groups of debt covenants to increase consistency among other debt instruments.

Load Forecasting, System Planning and DSP Development	
13	Develop evaluative criteria or other measures to assess the effectiveness of the planning process. Effectiveness should be measured based on specifics, for example: • Number and timeliness of system studies • Timeliness of development of PJDs • Quality of PJDs (e.g., do they contain all requisite information?) • Relative accuracy of conceptual level estimates
14	Perform detailed cost-benefit analyses consistent with Transmission Planning's analyses for projects related to thermal overload.
Transmission and Distribution (The most important recommendation for improving PSEG LI's T&D operations, preventive maintenance and continued improvement require workload resource quantification and can be found in **Chapter X – Work Management**.)	
15	Continue implementing the vegetation management program to meet annual targets. Complete the mainline hardening program.
16	Complete the Emergency Response Training for all employees as required.
17	Improve Emergency Response Training in the ERP to identify type of training and frequency by position.
18	Complete development of the CMMS.
19	Continue monitoring SAIFI both from a system and cause basis. Continue targeting and prioritizing programs that address reliability.
Program and Project Planning and Management	
20	Perform all policies, procedures and control functions that are currently and formally required. • PSEG LI should conduct all audits as required in the A&R OSA. • Adhere to formal document control policies and procedures. • PSEG LI should follow the PMP Playbook and its procedures
21	The URB management processes and controls should be audited annually until the next DPS Management Audit, to confirm adherence to its charter and control policies and procedures.
22	Develop and implement procedures related to quality assurance and quality controls for capital programs and projects.
23	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. • Assess the process used to develop and update estimates for completion. • 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 data true-up process. • Review and document inflation and escalation factors and analyses used to predict project completion costs for each project estimate. • 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. • Formally document project cost reviews at each level of estimate in detail and at various stages of project completion as called for in Project Cost Management (Procedure TD-PM-002-0004). • 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. • Continuously verify the accuracy of estimates versus the actual project cost and maintain a record of updates to the estimating database.

24	Utilize a WBS in the initial phases of the project justification and conceptual estimating, and continue their refinement as the project progresses. • Develop well-defined work packages that can be used to track and measure project performance based on earned value. • 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 PSEG LI's accounting 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. • 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.
25	Formalize and incorporate contingency management in capital project cost estimating and cost management. Formally report the expenditure of contingency funds separately from project estimates rather than inflate total project budget amounts. It is critical that reliable 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.
26	Define and report project management performance measures that focus on the effectiveness of cost estimation, earned value and schedule management. Project progress reports should be timely, and contain all information which is pertinent for their target audience. 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. • 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. • 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. • Establish processes for systematic schedule preparation, review and analysis.

	• 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. • Highlight: - 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.
Work Management and Outside Services	
27	Develop an integrated a work management system covering all PSEG LI operations, maintenance and construction resources that are based on engineered time standards and cover routine operations, repetitive maintenance activities, planned work, support requirements, and provide continuous feedback on workforce effectiveness. The system should be in an easy-to-use format expressed in man-hours, 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 work level versus resource histogram development and work plan process. • Enhanced methods to calculate workforce capacity and utilization. • Expanded workforce coverage in reports. • Documentation of processes for establishing workforce levels. • Documentation of criteria for adding contractor capacity. • Establish real time variance reporting for O&M and project costs. • Additional decision-making information to work plan
28	Fill gaps in the current management information reporting and organizational reporting relationships to support an integrated work management system. • Develop formal reports on trends in work load levels, workforce productivity and utilization. The analysis of these trends identifies areas that are performing well, where improvements are needed, and is a foundation for the development of strategies to improve work force performance. • Establish formal processes to use work management data for annual resource planning as part of the annual business planning activities of PSEG LI operations and maintenance. • Develop formal work management practices for PSEG LI engineering and design functions. The work management systems should have appropriate system tools to support the various individual and distinct engineering functional processes. Elements that should be formalized include: - Scheduling - Prioritization and planning - Resource allocation and leveling - Performance measurement

	- Budget planning and control - Vendor tracking - Document/drawing control - Records management - Procurement management - Time reporting
29	Develop overtime targets for PSEG LI operations and maintenance organizations based on economic analyses and verified industry norms.
30	Add KPIs for management positions. Review the design of monitoring and controlling reports to improve their usefulness.
Customer Operations	
31	At the time of the next bill redesign, revise bill formats to include missing information required by 16 NYCRR Parts 11 and 13 (e.g., definition of kW, late payment date line and an explanation as to how the bill can be paid).
32	Issue denial of service notices as required by 16 NYCRR Parts 11 and 13. Offer payment arrangements as required by Part 11.
33	Revise the processes used by PSEG LI to respond to complaints received by the DPS as follows: • Create a case file checklist to include in case files to ensure documentation is complete. • Develop an integrated program management approach to ensure customers are provided information on all programs available to them. One approach would be to create customer profile worksheet with cross reference to applicable programs and/or relevant protections. • Eliminate practice of hand calculations and implement use of excel template calculators. Modify the “DPS Complaint Response Form” to include: - Time and date customer complaint was created - Applicable customer contact timeline (e.g. 2-hour, next day etc.) - Time and date customer was contacted - Any special protections or customer assistance programs the customer was referred to - Date form submitted to DPS. • Implement a process to ensure PSEG LI includes copies of the DPS customer close out letters in the case files.
34	Modify the CTS system to improve DPS complaint tracking and reporting ability. Add data fields including: • The original source of complaints referred by DPS (i.e., direct from customer, Consultant, Government Official/Executive Correspondence). • Customer contact deadline. • Closeout deadline. • Resolution status field to differentiate between cases that are “Resolved and Closed” vs “Unresolved and Closed” • Indication the case is “Pending completion of future work” to allow for active follow-up. • Modify the Date Opened field to allow for capturing of time of day a case is created. • Modify Date Contacted field (default time of day set at 0:00) to force user to adjust time. Adjust internal processes to ensure data entry into this field.
35	Implement a Quality Assurance Program in Customer Relations. Recommended items for review include: • Data is entered in CTS • CAS diary entry includes the time customer contact occurred • Case files are completed • Appropriate tools and methodology are being used to calculate adjustments • Consistent treatment of customers with similar issues • Customers complaint concerns appropriately addressed • DPS Complaint Response Form is used to track response to DPS cases.
Outreach and Communications	
36	Measure the effectiveness of capital-project outreach, media relations and external affairs programs, to determine whether outreach efforts are cost-efficient, on target, and achieving results. Potential

	measurement options include surveys, focus groups, a media clip index, or attendance at public meetings.
37	On a pilot basis, evaluate the potential use and effectiveness of text messages and phone calls to customers on scheduled tree trim routes.
38	Measure the effectiveness of energy efficiency and low-income program outreach and marketing efforts.
39	Develop a more formalized process for determining the outreach budgets for capital projects, particularly Tier 3 and high scoring Tier 2 projects.
40	Update the External Affairs Handbook to reflect recent lessons learned, the findings in NorthStar's report, the items cited below, and the other recommendation cited in this chapter. • Expand the discussion of project scoring. • For all Tier 3 projects, update constituents as the project approaches its start date, or if there are significant project changes (e.g., scope, schedule, location/route, duration, or other item likely to impact the community such as overhead versus underground, pole heights, additional poles, traffic, outages). This is in addition to the annual update on the 5-year capital plan.
41	Formalize the External Affairs training and enhance it to include the following: • Outreach expectations and requirements (e.g., frequency and information to be communicated) • Scoring methodology and application of the scoring rubric in a consistent, objective manner • Documentation requirements • The External Affairs Handbook and other policies and procedures • Communication with the DPS • When various outreach activities/communications methods are required or should be employed • Developing budgets for capital project outreach.
42	Develop formal public outreach plans for each Tier 3 project (i.e., not a spreadsheet). At a minimum the plans should include the following, and should be updated as the project or anticipated outreach requirements change: • Description of the project, including timeline and key milestones • Checkpoints to identify any significant changes in project scope or timing • Scoring sheets and a discussion of key concerns and how to mitigate them • Discussion of alternatives considered • Project budget and detailed outreach budgets • Anticipated frequency of communications/timeline, planned outreach activities and materials.
43	Document meetings (date, attendees, topics discussed, takeaways) with impacted officials as required by the External Affairs Handbook.
44	Increase the specificity of capital project-related outreach: • Include more specific, detailed project information on public information meeting letters and notices. • All outreach materials (i.e., fact sheets and customer letters) resulting in additional poles, pole changes, a shift from underground to overhead cables should indicate such and provided detailed description. • Consider increased use of pictures and renderings in outreach materials, particularly the reliability web pages. • Add a link to PSEG LI's reliability web page on all outreach materials, particularly customer letters. Include dates materials were added to the reliability project pages of PSEG LI's website. • Consider an icon for "Upcoming projects in your neighborhood" or the equivalent to the www.psegliny.com landing page. • Include community/public meeting presentations on the reliability pages of PSEG LI's website.
Performance Management	
45	Develop and adhere to a schedule for completion of the annual metric identification and target setting process that provides for a final list of approved metrics at the beginning of the measurement year. Tier 1 Metrics, definitions, weightings and targets should be set no later than February 28. There should be a final sign-off on all of the aforementioned elements. Note: This is not intended to imply that the metric book must be completed by February 28; however, it should be done in an expeditious manner.

46	PSEG LI and LIPA should streamline its process to facilitate the establishment and measurement of meaningful operational metrics to monitor performance, incorporating DPS staff input, and potentially bifurcating the Tier 2 metrics. This might expedite the finalization of the Tier 1 metrics. Examples include: • Establish a smaller group of Tier 2 metrics used to test metrics for possible inclusion as a Tier 1 metric or to continue to monitor performance when a Tier 1 metric has been moved to a Tier 2 metric. • Establish a separate classification of metrics to be used to monitor performance in specific areas or for operational reporting. These metrics would not be tied to compensation and could then be used to address such items as the following: - Changes in regulatory requirements or NYS initiatives (e.g., Reforming the Energy Vision, Clean Energy) - Elements of LIPA’s Strategic Plan, Utility 2.0 or the IRP. - AMI implementation status - Issues identified by internal or external audits, including performance deficiencies identified by NorthStar’s audit. - Operational changes or revised priorities. - Tracking new initiatives or sub-elements of existing initiatives. - Metrics intended to address efficiency and effectiveness. - As examples, a number of the Tier 2 metrics used over time would more appropriately have been part of this category: social media followers, staffing levels permanent, percent of financial management reports delivered to LIPA.
47	LIPA and PSEG LI should continue to evaluate how to best incentivize service provider performance (Tier 1 metrics), drive continuous improvement and align the metrics with the focus of LIPA and PSEG LI’s long-term strategy/operational needs and industry best practices.
48	Define the metric calculation methodology to specify whether service restorations completed in exactly two hours should be included in the ETR Accuracy performance metric. NorthStar found the specified calculation methodology open to some interpretation. Currently, PSEG LI does not include restoration times of exactly two hours. This should be reconciled between PSEG LI and LIPA.
Fuel and Purchased Power	
49	Memorialize the process regarding PSEG LI conflict of interest in regional market activities (discussed in Section 4.18 of the A&R OSA) in the Contract Administration Manual (CAM).
Pension and OPEB	
	None

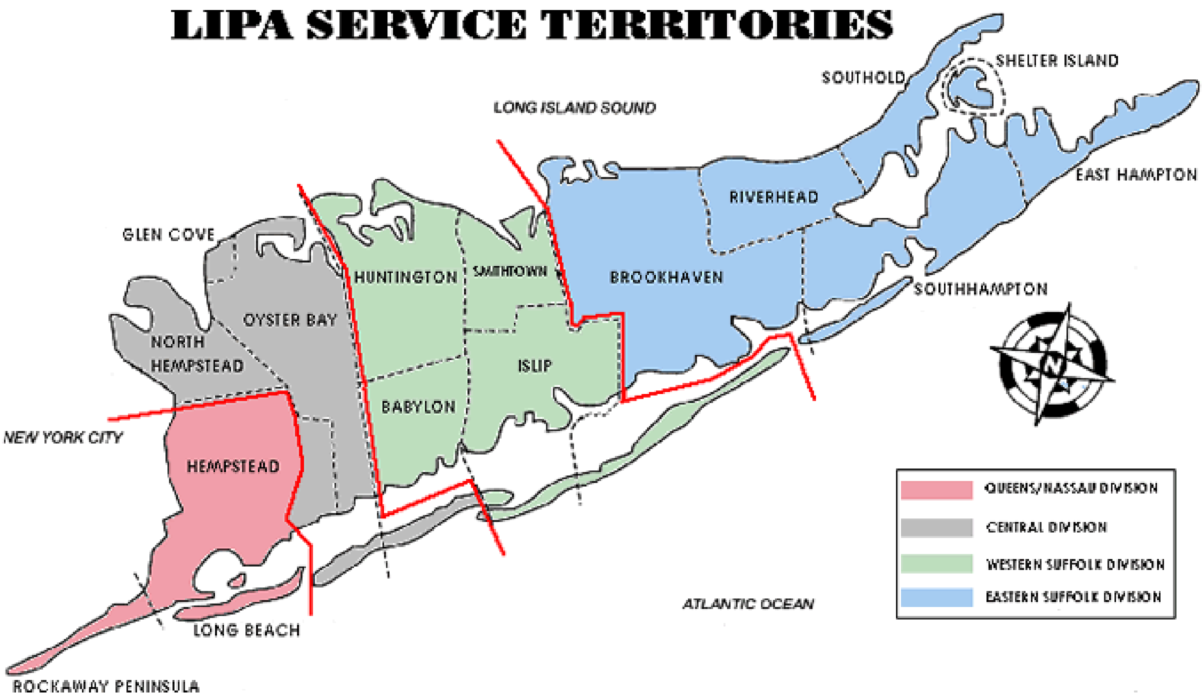
II. LIPA BACKGROUND AND PRIOR AUDIT

This chapter provides background information on the Long Island Power Authority (LIPA or the Authority) and the status of the implementation of recommendations resulting from the prior management audit as the recommendations pertain to LIPA and its primary outside service provider – PSEG Long Island, LLC (PSEG LI or the service provider).[1]

A. INTRODUCTION

LIPA provides electric delivery service to approximately 1.1 million customers in Nassau and Suffolk Counties (with certain limited exceptions) and a portion of Queens County known as the Rockaways (Service Area). The population of the Service Area is approximately 2.9 million. **Exhibit II-1** provides an overview of the service territory.

Exhibit II-1



During 2016, approximately 53 percent of the Authority's annual retail revenues were received from residential customers, 44 percent from commercial customers, and three percent from street lighting, public authorities and other revenue sources. The largest customer, the Long Island Rail Road (LIRR), accounted for less than two percent of total sales and less than two percent of revenues in the Service Area. In addition, the ten largest

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[1] PSEG LI is a subsidiary of the utility holding company in New Jersey – Public Service Energy Group (PSEG)

customers in the service area accounted for approximately seven percent of total sales and less than seven percent of revenues. Electric revenue for 2016 totaled $3.40 billion, a decrease of $106 million compared to 2015 due to lower power supply costs, as shown in **Exhibit II-2**.

Exhibit II-2
LIPA Annual Revenues
(in Thousands)

Revenues from Sales of Electricity	2016	2015	2014
Residential	$1,815.9	$1,860.9	$1,883.3
Commercial	1,492.8	1,537.8	1,618.3
Street lighting, public authorities and other	90.4	106.5	112.4
Total	**$3,399.1**	**$3,505.2**	**$3,614.0**

Source: http://www.lipower.org/pdfs/company/LIPA%20Annual%20Report%202016.pdf

Operating expenses for 2016 totaled $3.16 billion, a decrease of $24 million compared to 2015 primarily due to lower power supply costs of $161 million, which was partially offset by higher storm restoration costs and higher PSEG LI operating costs. For the year ended December 31, 2016:

- Approximately 46 percent of the Authority's expenses were associated with the cost to provide power supply, including: (i) commodity costs; (ii) purchased power costs, including the Amended and Restated Power Supply Agreement (A&R PSA) costs; and, (iii) the Authority's share of operating costs associated with the Nine Mile Point Unit 2 (NMP2) nuclear generating station.
- Operations and maintenance (O&M) expenses associated with the transmission & distribution (T&D) system accounted for 20 percent of the total expenses in 2016.
- Payments made in lieu of taxes (PILOTs), taxes paid pursuant to the contract on the A&R PSA generating units, and other taxes and assessments were 16 percent of expenses.
- Interest expenses were 10 percent of expenses.
- Depreciation and amortization was eight percent.

History of LIPA

The LIPA Act

The Authority is a corporate municipal instrumentality of the State of New York (State, NY or NYS).[2] The Authority was established by Chapter 517 of the Laws of 1986 (the LIPA Act) to control electricity costs within the service territory of the Long Island Lighting Company (LILCO).[3] In 1989, LILCO entered into an agreement to sell the Shoreham Nuclear Power Plant to LIPA. As part of the agreement, Long Island ratepayers would bear the cost of Shoreham over time.

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[2] http://www.lipower.org/pdfs/company/LIPA%20Annual%20Report%202016.pdf

[3] Office of the State Comptroller, "Public Authorities by the Numbers: Long Island Power Authority", October 2012 (https://osc.state.ny.us/reports/pubauth/lipa_by_the_numbers_10_2012.pdf)

The LIPA Act requires that any bond resolution of the Authority contain a covenant that it will at all times maintain rates, fees, or charges sufficient to pay the costs of: operation and maintenance of facilities owned or operated by the Authority; PILOTS; renewals, replacements, and capital additions; and the principal of, and interest on, any obligations issued pursuant to such resolution as the same become due and payable. The LIPA Act is key to LIPA's tax-free status as a public authority while not triggering debt covenants. In addition, the Authority must establish or maintain reserves or other funds or accounts required or established by or pursuant to the terms of such resolution. The Authority's Board of Trustees (Board or BOT) is empowered under its enabling statute to set rates for electric service in the Service Area. However, , LIPA cannot implement an increase in average customer rates exceeding 2.5 percent over a 12-month period or extend or re-establish any portion of a temporary rate increase over 2.5 percent, without a Department of Public Service full evidentiary hearing.[4]

On May 28, 1998, LIPA acquired LILCO's electric T&D system, as well as certain other assets and became the primary supplier of electricity on Long Island.[5] That same year, LILCO's remaining assets, including its electrical generating facilities, were merged with Brooklyn Union Gas, creating a new publicly-traded utility corporation called KeySpan Corporation (also known as KeySpan Energy or KeySpan). As part of the acquisition, LIPA also acquired an undivided 18 percent interest in the NMP2 generating facility, located in upstate New York. In October 2007, National Grid LLC (National Grid) purchased KeySpan and legally assumed responsibility for KeySpan's contracts with LIPA.[6]

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 Operations Services Agreement (OSA), signed December 28, 2011, for the operations and maintenance of LIPA's system effective January 1, 2014 for a period of ten years.

PSEG Long Island LLC (PSEG LI), a wholly owned subsidiary of Public Service Enterprise Group (PSEG) that is fully dedicated to the Authority's Long Island operations, was selected as the Authority's service provider, to provide electric service to LIPA's service area, pursuant to the OSA. As discussed below, as the result of the LIPA Reform Act in 2013, the terms of the OSA were modified, and PSEG LI now provides service under an Amended and Restated OSA (A&R OSA).[7] The A&R OSA provides for the operation, maintenance and related services for the T&D system. PSEG LI is paid a management fee and may earn incentives related to specified performance metrics. Essentially all costs of operating and maintaining LIPA's T&D system incurred by PSEG LI are passed through to, and paid for, by LIPA. LIPA also has a contract with PSEG Energy Resources and Trade LLC (PSEG ER&T) to provide services related to fuel and power supply management and

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[4] LIPA Reform Act (June 17, 2013).

[5] https://osc.state.ny.us/reports/pubauth/lipa_by_the_numbers_10_2012.pdf

[6] https://osc.state.ny.us/reports/pubauth/lipa_by_the_numbers_10_2012.pdf

[7] DR 4 Attachment Amended & Restated OSA 2013 dated December 31, 2013.

certain commodity activities. Separately from its contract with PSEG ER&T, LIPA maintains power purchase agreements with third party power generators.

Major Operating Agreements

- *Amended and Restated Operations Services Agreement (A&R OSA)*: Effective January 1, 2014, PSEG LI provides operations, maintenance and related services for the T&D system under the A&R OSA. The A&R OSA expires December 31, 2025, and includes a provision that if PSEG LI achieves certain levels of performance based on established criteria during the first 10 years, the parties will negotiate an eight-year extension with substantially similar terms and conditions. During the years ended December 31, 2014, 2015 and 2016, PSEG LI was paid a management fee including incentives totaling approximately $44 million, $39 million and $62 million, respectively.[8] For 2014, 2015 and 2016, PSEG LI was paid incentive fees totaling $5.5 million, $5.2 million and $9.2 million, respectively.

- *Amended and Restated Power Supply Agreement (A&R PSA)*: National Grid Generation (NG Generation) provides capacity and energy from its oil and gas fired generating plants located on Long Island under the A&R PSA, which provides for the purchase of generation (including capacity and related energy) from these fossil fuel generating plants. The A&R PSA commenced May 28, 2013, and expires April 30, 2028.

- *Fuel Management Agreement (FMA) and Power Supply Management Agreement (PSMA)*: PSEG ER&T provides fuel management services for both the PSA generating facilities and other units for which LIPA is responsible for providing fuel. Certain other services related to power supply management and commodity activities are also provided by PSEG ER&T. During the years ended December 31, 2015 and 2016, PSEG ER&T was paid a management fee totaling approximately $16 million and $17 million, respectively. The agreement with PSEG ER&T expires December 31, 2025, and will continue to be automatically extended until December 31, 2033 if there is an extension of the A&R OSA.[9]

The LIPA Reform Act

The LIPA Reform Act which was passed and codified as Chapter 173, Laws of New York on June 21, 2013, by the New York State Assembly and Senate, significantly changed LIPA's role.[10] The LIPA Reform Act is divided into two parts, Part A and Part B.

Part A addresses the reorganization of the Authority and imposed new substantive obligations on any service provider and effectively shifted major operational and policy-making responsibilities for the T&D system from LIPA to PSEG LI, including responsibilities for capital expenditures, budgets, and emergency response. The LIPA

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[8] 2014 Management Fee: http://www.lipower.org/newscenter/LIPA2015ProposedBudget.pdf page A-4.

[9] http://www.lipower.org/papers/Appendix7.pdf Article 2 – Term (2.1.iii)

[10] http://legislation.nysenate.gov/pdf/bills/2013/S5844

Reform Act requires that staffing at the Authority be kept at levels only necessary to ensure that the Authority is able to meet obligations with respect to its bonds and notes and all applicable statutes and contracts, and to oversee the activities of PSEG LI.[11]

Part A also created a new Long Island-based office of the DPS to review and make recommendations to LIPA and/or PSEG LI related to:

- The operations and terms and conditions of service.
- Rates and budgets established by, the authority and/or its service provider including charges related to energy efficiency and renewable energy programs.
- Ensuring that the authority and the service provider provide safe and adequate transmission and distribution service at rates set at the lowest level consistent with sound fiscal operating practices.
- Part A also gives DPS the responsibility to investigate and mediate customer complaints. Additionally, the DPS shall, upon notification to LIPA, undertake a comprehensive and regular management and operations audit of the authority pursuant to subdivision (bb) of section one thousand twenty-f of the public authorities law.[12] Comprehensive management and operations audits shall be initiated at least once every five years.[13]
- The LIPA Reform Act requires LIPA's service provider, PSEG LI, to annually prepare and maintain an emergency response plan to assure the reasonably prompt restoration of service in the case of an emergency event, and to establish separate responsibilities of the Authority and its service provider. The emergency response plan must be submitted to the DPS for review on or before February third each year.[14]
- PSEG LI must submit reports to DPS detailing PSEG LI's planned capital expenditures and performance related to the metrics in the A&R OSA.

The PSEG LI management company consists of approximately 20 employees at the director level and higher. The PSEG LI service company consists of approximately 2,350 employees, which includes a substantial majority of incumbents from the National Grid workforce, as well as new hires at the manager level and lower.[15]

Implementation of the LIPA Reform Act required the transfer of substantial operational duties and obligations from LIPA to PSEG LI and greater operational flexibility for PSEG LI to carry out its duties. In response to the LIPA Reform Act, LIPA re-negotiated the OSA with PSEG LI to address the changed relationship between the parties in connection with the

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[11] http://legislation.nysenate.gov/pdf/bills/2013/S5844 and Prospectus - LIPA Electric System Revenue Bonds 2017

[12] http://legislation.nysenate.gov/pdf/bills/2013/S5844 Part A, Section 2

[13] http://legislation.nysenate.gov/pdf/bills/2013/S5844 Part A, Section 2.4.bb.2

[14] http://legislation.nysenate.gov/pdf/bills/2013/S5844 Part A, Section 2.4.cc.2

[15] Prospectus - LIPA Electric System Revenue Bonds 2017

provision of electric service.[16] On January 1, 2014, PSEG LI became the retail brand for electric service on Long Island.[17]

Part B of the LIPA Reform Act, also referred to as the Securitization Law, established the Utility Debt Securitization Authority (UDSA). The Securitization Law's sole purpose is to provide a legislative foundation for the UDSA's issuance of restructuring bonds to allow the Authority to retire a portion of its outstanding indebtedness, providing savings to the Authority's customers on a net present value (NPV) basis. The restructuring bonds are repaid by an irrevocable, non-bypassable restructuring charge on all the Authority's customers. The UDSA has a governing body separate from that of the Authority and has no commercial operations.[18]

In accordance with the Securitization Law, the UDSA sold $2.0 billion of bonds in 2013. In 2015, the Securitization Law was amended to permit UDSA to issue restructuring bonds in an aggregate principal amount not to exceed $4.5 billion.[19]

Three-Year Rate Plan

LIPA is not subject to rate regulation by the NYS PSC. The LIPA Reform Act required DPS to establish an evidentiary process for an initial Three-Year Rate Plan (2016 – 2018) and any subsequent LIPA proposal that would increase base rates by more than 2.5 percent of total revenues. In accordance with the LIPA Reform Act, on January 30, 2015, the Authority and PSEG LI submitted a Three-Year Rate Plan to the DPS for rates and charges to take effect on or after January 1, 2016. Evidentiary hearings were held and other parties had the opportunity to present evidence and cross-examine the Authority, PSEG LI, and DPS witnesses. Following the review of the Three-Year Rate Plan by DPS, on September 28, 2015, DPS submitted its rate recommendation to the Authority's Board (the DPS Recommendation). The Authority's Board met on October 19, 2015, to consider the DPS Recommendation and did not make a preliminary determination of inconsistency; therefore, pursuant to the LIPA Reform Act, on December 16, 2015, the Authority's Board implemented the Three-Year Rate Plan set forth in the DPS Recommendation.[20]

Regulations

As a public authority, LIPA is subject to a variety of rules and regulations and oversight by various State Agencies, including the following.

- **Department of Public Service (DPS)** – As discussed above, the LIPA Reform Act created a new Long Island-based DPS office to review LIPA and/or PSEG LI with regard to core utility operations, investigate and mediate customer complaints, and

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[16] Prospectus - LIPA Electric System Revenue Bonds 2017

[17] Prospectus - LIPA Electric System Revenue Bonds 2017

[18] http://legislation.nysenate.gov/pdf/bills/2013/S5844 Part B

[19] http://www.lipower.org/UDSA/docs/UDSA%202016A.pdf Summary, page ii

[20] Matter No. 15-00262, Department Rate Recommendation (DRR) on LIPA and PSEG LI Three-Year Rate Proposal (issued September 28, 2015).

undertake management and operations audits.[21]

- **Public Authorities Control Board (PACB)** – Pursuant to the LIPA Act, the Authority is required to obtain approval of the PACB before undertaking any "project." The PACB was created in 1976 in response to the growing amount of Public Authority Debt. It is codified in Section 50 of the NYS Public Authorities Law (PAL). The PACB is a five-member board appointed by the Governor. A "project" is defined by the LIPA 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.

- **Office of the New York State Comptroller (NYS Comptroller)** – Pursuant to the LIPA 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 LIPA 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 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."

- **Public Authorities Reform Act (PARA)** – PARA was signed into law in December 2009. 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). 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 Chief Executive Officer (CEO), mission statements and measurement reporting, subsidiaries of public authorities, public authority debt, and whistleblower protection.

- **State Administrative Procedures Act (SAPA**) – Changes to LIPA's tariff and regulations, are subject to SAPA requirements. SAPA requires: notice published in the *New York State Register*; a proposal memo available on LIPA's website and at its headquarters; a 60-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

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[21] LRA

meeting; and BOT discussion and vote on the resolution.[22]

Roles and Responsibilities

The roles and responsibilities of the three major entities involved in the electric utility function: LIPA, PSEG LI and the Long Island Department of Public Service (DPS LI) can be confusing at times. For this reason we have highlighted the following as established by the LIPA Reform Act ("Reform Act"), and the Amended and Restated Operations Services Agreement ("OSA") between LIPA and PSEG LI.

- LIPA's role is as follows:

  - As asset owner and contract manager, to maintain the integrity of the LIPA T&D System and other asset base through contract oversight of PSEG LI's operation and management of the T&D System and achievement of the performance metrics, which may be adjusted, as set forth in Section 4.3 of the OSA, and oversight of other Operations Services performed by the Service Provider under the OSA, including power supply and management.
  - Manage LIPA's financial and debt responsibilities (including budget related items to support both), wholesale market policy, approval of fuel and power contracts, and comply with related bond covenants and resolutions.
  - Prepare the LIPA portion of the budget and approve the annual operating and capital budgets submitted by PSEG LI subject to the provisions of the OSA.
  - Set rates and charges, through the ratemaking process outlined in the OSA and as required by the Public Authorities Law (LIPA Act) and the Reform Act.
  - Manage LIPA contracts not assigned to the Service Provider in the OSA.
  - Manage internal LIPA staff and comply with legal and regulatory obligations and responsibilities under applicable statutes and regulations.
  - Make the final decision on customer complaint appeals based on written recommendation provided by DPS LI.
  - Provide staffing support and resources to the LIPA Board of Trustees and other corporate governance functions.
  - Consult with PSEG LI on the preparation and maintenance of an emergency response plan as required by the Reform Act.

- PSEG LI's role is as follows:

  - For all matters below, PSEG LI will function in accordance with prudent utility practices and as appropriate, in a manner that is consistent with other electric utilities in New York. As asset manager, to manage, operate and maintain the T&D System and set related plans, policies, procedures and programs (subject to LIPA's bond and other financing obligations) (see Article 4 of the OSA).

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[22] https://www.nysenate.gov/legislation/bills/2017/s5795/amendment/a

  - Prepare, in consultation with LIPA, an emergency response plan and manage emergency preparedness, response and reporting (see Article 4 of the OSA and the Reform Act).
  - Prepare annually the Utility 2.0 Plan, long range capital and operating plans, and, if it elects to do so, to propose optional capital investments (which PSEG LI may propose to fund) subject to the provisions of and LIPA's rights under the OSA.
  - Be the name and face of operations in the LIPA service area with full authority to determine policies and procedures with respect to use of its name and service mark in all media and public communications on utility-related matters.
  - Prepare the annual operating and capital budgets and management of the budgets within the parameters of the OSA. Prepare and submit, together with LIPA, rate filings to DPS, as required by the Reform Act (see Article 6 of the OSA).
  - Operate the T&D System in a manner that provides the lowest level of charges consistent with safe and reliable service, including necessary oversight of physical and cyber security.
  - Annually, submit for review by DPS LI the Service Provider's planned capital expenditures.
  - Annually, submit for review by DPS LI proposed plans to implement energy efficiency and renewable energy programs, demand response, distributed generation or advanced grid technology programs, and any other related programs; and consider, consistent with system reliability, such programs and options in establishing capital plans.
  - Provide information related to the provision of Operations Services and cooperate with LIPA as provided in the OSA, and with DPS LI staff as necessary for each to perform their respective obligations in a timely manner.

- DPS LI's role, as specifically provided in the LIPA Reform Act, is carried out in a manner consistent with NYS DPS regulation of other New York electric utilities, and is highlighted as follows:

  - Generally review and make recommendations to LIPA and as appropriate to PSEG LI, with respect to the operations and terms and conditions of service and the rates and budgets established by LIPA and PSEG LI and with respect to each specific area of DPS review enumerated in the Reform Act. DPS LI has noted that its focus areas include:
    - Review of proposed budgets for sufficiency to meet LIPA's statutory obligations, including examination of budget items for tree trimming and vegetation management, inspection programs, compliance with safety standards, emergency operations and repairs, provision of safe and reliable service, capital projects, and other programs;
    - Review of tariffs; and
    - Review LIPA and PSEG LI's actual financial and operational books and records.
  - Review and make recommendations on proposed rates in rate plans submitted to DPS and other rate submissions in accordance with the Reform Act, and make recommendations designed to ensure that the authority and the Service Provider

provide safe and adequate T&D service at rates set at the lowest level consistent with sound fiscal operating practices.

- Resolve, where possible, all residential and non-residential customer complaints. Provide written recommendations to designated LIPA and/or PSEG LI staff for corrective action on unresolved complaints, and provide written recommendation to LIPA management for decision on appeal.
- Review and make recommendations with respect to the emergency response plan of LIPA and PSEG LI and with respect to the performance of PSEG LI in restoring service and meeting the requirements of the emergency response plan during an emergency event, including storm response of PSEG LI, and assessment of the reasonableness of storm costs.
- Review PSEG LI's annual proposed capital expenditure plans and make recommendations for improvements in the manufacture, conveying, transportation, distribution or supply of electricity, or in the methods employed by the Service Provider, to allow for safe and adequate service.
- Perform a comprehensive management and operations audit of LIPA and PSEG LI, the first such audit having been completed, the second such audit to be commenced in 2016, and subsequent audits to be performed periodically thereafter. Provide the results and recommendations to the LIPA Board as provided for in the Reform Act.
- In the management and operations audit, review overall operations and management of LIPA and PSEG LI and make recommendations, where appropriate, with respect to LIPA's duty to set rates at the lowest level consistent with sound fiscal operating practices and to provide safe and adequate service. Review the application, if any, of the performance metrics designated in the OSA and the accuracy of the data relied upon with respect to such application.
- Review and make recommendations with respect to plans for the implementation of energy efficiency and renewable energy programs, demand response, advanced grid technologies, distributed generation, net metering, and customer empowering programs and policies.
- Review the data in PSEG LI's metrics report and make recommendations with respect to PSEG LI's incentive compensation calculation.
- Review and make recommendations with respect to the net metering program implemented under subdivision (h) of section one thousand twenty–g of the Public Authorities Law.

B. IMPLEMENTATION OF THE RECOMMENDATIONS FROM THE DEPARTMENT'S COMPREHENSIVE MANAGEMENT AND OPERATIONS AUDIT OF LIPA IN MATTER NO. 12-00314

In 2012 NorthStar was retained by the DPS to conduct a Management and Operations Audit of LIPA, identified as Matter No. 12-00314. The Final Report of the LIPA Comprehensive Management and Operations Audit was released in September 2013 (2013 Final LIPA Audit Report). Throughout the audit process, a number of themes emerged that crossed functional areas and represented overarching issues that required focused attention moving forward. These included:

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.

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.

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.

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

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

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

The 2013 Final LIPA Audit Report contained a total of 83 recommendations. NorthStar's 2013 audit conclusions and recommendations were 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 with PSEG LI dated December 28, 2011. These recommendations focused on areas where improvements were needed, with limited knowledge of how the LIPA Reform Act, the selection of PSEG LI as the service provider, and the A&R OSA would alter LIPA roles and responsibilities, and how the recommendations would ultimately be implemented.

C. EVALUATIVE CRITERIA

The 2016 audit of LIPA, included in its scope, evaluation of the following:

- Does LIPA/PSEG LI have an effective system in place for resolving, following up, and implementing the 2013 audit recommendations?
- Have the prior management audit recommendations been effectively implemented?

D. FINDINGS AND CONCLUSIONS

1. LIPA did not have an effective system in place for resolving, following up on, or implementing the 2012-2013 management audit recommendations.

- NorthStar noted that LIPA's Internal Audit plans for 2014 to 2017 did not include follow up on the 2013 audit recommendations.[23]

- NorthStar requested documentation related to LIPA's implementation of the 2013 management audit recommendations, including responsible managers, progress and completion status.[24] LIPA's response to NorthStar's request took over five months to gather information.[25]

  - LIPA stated that all of the prior audit recommendations were adopted by LIPA, and PSEG LI was directed to implement those within its responsibilities as the new service provider effective January 2014.[26]
  - LIPA's reports on implementation appear in numerous separate files, named by audit report chapter.[27]

- LIPA provided a summary table of the organization responsible for each recommendation and a table listing senior management and staff currently responsible for each recommendation's implementation.[28] LIPA's employee assignments to audit recommendations show that in many cases these employees have been in their respective positions for only a short time.[29]

- LIPA stated that because drafting of the 2013 Final LIPA Audit Report largely preceded passage of the LIPA Reform Act of 2013 and entirely preceded subsequent amendment and revisions of the A&R OSA, LIPA and PSEG LI have in some instances reassigned responsibility for implementation of recommendations.[30] Perhaps the reassignment of implementation could have caused some ambiguity as to responsibilities. Nevertheless, NorthStar's review concentrated on whether the recommendations were *effectively* implemented, regardless of which entity was responsible.

- LIPA accepted responsibility for 43 out of 83 recommendations contained in the 2013 management audit.[31] As of August 2017, LIPA reported that 40 out of 43 recommendations were completely implemented and the remaining 3 were

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[23] DR 33, 34 and 240 Attachments 2014 – 2017.

[24] DR 240

[25] DR 240

[26] DR 240

[27] DR 240 – INTRO, Attachment 1 – 29 and numerous Responses

[28] DR 240 Response and Attachment 1

[29] DR 1 Attachment 1 and DR 240 – "INTRO" – all positions late 2016

[30] DR 240 Response

[31] DR 240 – INTRO

substantially complete.[32]

- LIPA did not develop a formal implementation plan monitoring or confirming the implementation of audit recommendations to be implemented by LIPA and/or PSEG LI.[33] However, during the 2015 rate case discovery process LIPA provided a status summary.[34] This LIPA testimony indicated that:
  - Twenty-two of the 40 PSEG LI audit recommendations had been addressed.
  - LIPA direct testimony indicated that 35 of 43 Authority actions had been completed.

- The current audit concluded that 38 recommendations were completed, 2 recommendations were ongoing and partially completed. Three recommendations were no longer applicable. See **Exhibit II-3** below for further details.

2. PSEG LI did not have an effective system in place for resolving, following up on, or implementing the 2012-2013 management audit recommendations but included many of the audit recommendations in their transition Change Initiatives Program.

- PSEG LI accepted responsibility for the 40 audit recommendations that were not addressed by LIPA.[35]

- PSEG LI covered many of the audit recommendations in their "Change Initiatives Program" launched in 2014, aimed at meeting some of the same goals and outcomes.[36] Highlights of this program included:
  - Interactive Voice Response implementation
  - Customer Satisfaction Steering Committee
  - New Call Center Voice Analytics
  - Balanced Scorecard package
  - OMS implementation
  - Enhanced Capital Project Planning and Project Management

- PSEG LI's December 2014 Change Initiative Summary reported most of the initiatives completed or nearly completed.[37]

- PSEG LI's own Internal Audit Plan for CY2015 included an audit titled "Implementation of NorthStar audit recommendations (Phase 2 & 3)."[38] Upon review of the audit report and observations, the report merely indicated that PSEG LI

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[32] DR 240 Attachment 1
[33] DR 240
[34] January 30, 2015, Matter No. 15-00262 and Fact Verification
[35] DR 240
[36] DR 411
[37] DR 411 Attachment 196
[38] DR 34 Attachment 2

management had "addressed" the recommendations and did not determine whether the recommendations had been implemented or whether implementation was effective. When NorthStar evaluated this audit in greater detail, PSEG LI Internal Audit stated:[39]

> "The work was a "Review," not an "Audit." The objective of the Review was to determine whether management addressed all of the recommendations. Had we conducted a full-scope audit, it's possible we may have had some observations, but we were only asked to do a Review."

- NorthStar's review determined that of PSEG LI's 40 recommendations accepted, 24 recommendations were completed, 4 recommendations were not implemented and 11 recommendations were ongoing or partially completed. One recommendation was no longer applicable. See **Exhibit II-4** below for further details.

3. **Many of the 2013 Final LIPA Audit Report recommendations have been implemented. However, LIPA's and PSEG LI's assertion that all of the recommendations were implemented is not entirely correct and the effectiveness of those that have been implemented is mixed.**

- NorthStar's evaluation of the 2013 audit report recommendations is shown in **Exhibit II-3** and **II-4**. Completed recommendations are shown as **green**, partial or ongoing recommendation implementation is shown in **yellow**, and those lacking meaningful progress are shown in **red**.

- Some of the 2013 audit report recommendations are no longer applicable to LIPA based on the LRA and A&R OSA. These are not color coded in the exhibit.

- The significance of NorthStar's recommendations varies both in the degree to which they require compliance with various policies/procedures, contract and legislative documents as well as the potential for adverse risk or economic impact on the ratepayer. The importance of recommendations from the 2013 audit that are partially implemented, in process or lacking meaningful progress are therefore designated as high, medium or low on **Exhibits II-3** and **II-4.**

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[39] DR 450, Attachment, and email clarification dated September 6, 2017.

Exhibit II-3
Summary of Recommendations for LIPA's Implementation and NorthStar's Assessment of Implementation

Rec #	2013 Audit Report Recommendation	Sig.	Effective Implementation
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.		All aspects would include for example, customer service functions, capital project management, etc. LIPA is currently undertaking initiatives in succession planning, leadership, performance management, etc.
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.		LIPA has made recent improvements to this process but more quantitative targets are possible.
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.		The uncertainty of Trustee terms remains a Trustee concern.
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.	**High**	Ongoing: Committee charters state coverage but Trustee orientation and training can be improved, regular review and involvement is limited.
5.4.3	Explore options for enhancing communication with the public regarding BOT activities, including mechanisms for providing response to public comments.	**Medium**	Ongoing: Public comment and response to public comments can be improved.
5.4.4	Develop a proactive strategy to guide the BOT in recruiting, retaining, and developing LIPA Officer-level personnel.		🟩

Rec #	2013 Audit Report Recommendation	Sig.	Effective Implementation
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.		ERM program development continued through 2015 and 2016. The ERM program continued to evolve in 2016-2017. Implementation ongoing.
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.		In 2016, LIPA adopted a more formal approach to strategic planning which is consistent with standard practices. LIPA staff prepared the Operations and Oversight Plan for 2017-2019. This plan identifies the significant new initiatives to be undertaken directly by the LIPA staff, as distinguished from PSEG LI over the next three years. In essence, it is LIPA's business plan. Implementation ongoing.
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.		The ERM program is still in development. The strategic planning process has improved and certain Board policies contain performance metrics (largely for areas of PSEG LI operations which are tied to the A&R OSA metrics); however, this has been done to a much lesser extent for areas of LIPA responsibility.
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.		LIPA created an audit function and capabilities strengthened.
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.		By letter dated October 2, 2013 to the DPS, LIPA documented its recommendation to adopt all recommendations in the 2013 Report. Adoption and implementation plans not effectively developed. BOT quarterly updates on implementation progress not apparent.
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.		LIPA recommended evaluation in the next audit, yet many recommendations have not been addressed. This does not relieve LIPA of implementation or its own progress evaluations.

Rec #	2013 Audit Report Recommendation	Sig.	Effective Implementation
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.		On December 31, 2013, the NYPSC Emergency Performance Measures were added to the Amended and Restated OSA, as Appendix 13. These are storm-based and thus not reported with the Monthly Balanced Scorecard Results.
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.		Coordination with F&A Committee strengthened. Implementation related to Rec. 7.4.1 and 7.4.4.
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.		

Rec #	2013 Audit Report Recommendation	Sig.	Effective Implementation
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.		🟩
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.		🟩 Improvements to the process and tracking system identified in the current audit report.
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.		Discussion on PSEG LI web site.
15.4.10	Improve the information, links and visibility of BOT meetings, minutes and related documents and resources on LIPA's website.		🟩 Completed 6-5-2018.

Rec #	2013 Audit Report Recommendation	Sig.	Effective Implementation
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.		🟩
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.		🟩

Rec #	2013 Audit Report Recommendation	Sig.	Effective Implementation
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 II-4
Summary of Recommendations for PSEG LI Implementation and NorthStar's Assessment of Implementation

Rec #	2013 Audit Report Recommendation	Sig.	Effective Implementation
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.	**High**	Ongoing: Only a certain number of capital improvement projects can be quantified and based on a cost/benefit analysis.

Rec #	2013 Audit Report Recommendation	Sig.	Effective Implementation
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.		Deliverables are defined but not entirely implemented or adhered to.
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.	**High**	Ongoing: PSEG LI continues to develop and implement performance measures focusing on the effectiveness of cost estimates and project scheduling.
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.	**High**	Ineffective: PSEG LI does not use an industry accepted WBS
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.	**High**	Ongoing: PSEG LI is improving the process but presently does not accurately estimate projects. Poor estimating results in poor project management decisions.
10.4.7	Develop a capital project cost forecasting/trending capability.	**Low**	Ongoing: As noted above.
10.4.8	Incorporate contingency management in capital project cost estimating and cost management.	**Medium**	Ineffective: Poor project estimates are increased with a risk and contingency factor, ranging from 40 percent for an office level estimate to ten percent for a definitive estimate. These factors artificially inflate project estimates as the factors appear unsubstantiated
10.4.9	Formalize capital project change order management controls.		🟩
10.4.10	Improve periodic capital progress reporting.	**Medium**	Ongoing: The procedures developed to date address many components of capital project delivery, and will continue to support project management and control.
10.4.11	Improve capital project document control.	**Medium**	Ongoing: Procedures developed to date identify documents but implementation will continue.
10.4.12	Perform capital project schedule management.	**Medium**	Ongoing: PSEG LI's project schedule management will continue to improve
12.4.1	Increase the effectiveness of the vegetation management program by further refining analysis of tree-related reliability.		🟩

Rec #	2013 Audit Report Recommendation	Sig.	Effective Implementation
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.	**Low**	Ongoing: PSEG LI has a reasonable approach to repair/replace decision-making but it does not yet include cost/benefit analyses.
12.4.3	Establish an asset management model that supports the LIPA T&D preventive maintenance program. A	**Medium**	Ongoing: PSEG LI recently created an Asset Strategy group in late 2016 to provide increased support to the preventive maintenance programs. Full implementation expected in 2020.
13.4.1	Develop an integrated work management system that formalizes planned work, support requirements, and provides continuous feedback on workforce effectiveness.	**High**	Ineffective: PSEG LI does not yet use work management systems to effectively plan, monitor and control the work of major work force groups.
13.4.2	Fill gaps in the current management information reporting and organizational reporting relationships to support an integrated work management system.	**Medium**	Ineffective: PSEG LI does not yet use work management systems to effectively plan, monitor and control the work of major work force groups.
14.4.2	Develop improved service levels and service level standards throughout the customer service organization, both operational and OSA-level.		🟩
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.		Aligned with PSC policy for IOUs.
14.4.9	Replace CAS within the next five years per the schedule proposed by PSEG LI.		Updated cost-benefit analysis indicates system continues to operate appropriately and satisfy business needs and that other customer-facing improvements (such as the new Integrated Voice Response system) would prove more beneficial.
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.		🟩

Rec #	2013 Audit Report Recommendation	Sig.	Effective Implementation
15.4.4	Develop a comprehensive, coordinated communications, government and public affairs strategy and associated policies/procedures.	**Medium**	Ongoing: Communications are performed by a number of organizations. External Affairs developed a handbook for reliability projects and adopted a more proactive approach; however, additional improvements are possible as discussed later in this report.
15.4.5	Communicate issues of significance to customers regularly and in a timely manner.	**Medium**	Ongoing: Improvements are warranted in the area of capital projects.
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 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.		🟩

Rec #	2013 Audit Report Recommendation	Sig.	Effective Implementation
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.		🟩

E. RECOMMENDATIONS

1. LIPA and PSEG LI should work with the DPS to determine which of the outstanding recommendations from the 2013 are still relevant and should be implemented.

2. LIPA and PSEG LI should develop an implementation plan for all audit recommendations (new recommendations and outstanding recommendations that LIPA, PSEG LI and DPS determine remain relevant) within 90 days of the Final Audit Report acceptance and submit the implementation plan to the LIPA Board of Trustees and the DPS. The Report could take the form required of the IOUs.

3. LIPA Internal Audit should perform a comprehensive audit of the implementation status of all audit recommendations annually until the next DPS audit is performed. The results of LIPA's audit should be submitted to LIPA executive management, the LIPA Board of Trustees, PSEG LI, and the DPS. Within each LIPA audit:

    - An evaluation of progress performance should be included.
    - A progress tracking document should show activities completed to date and those in process.
    - Any revisions to completion targets should be highlighted for management review.

III. EXECUTIVE MANAGEMENT AND GOVERNANCE

This chapter provides the results of NorthStar's review and assessment of LIPA's executive management and corporate governance, including the following:

- LIPA's mission, goals and objectives.
- Oversight and organizational relationships within LIPA and PSEG LI.
- Current and future organizational structure.
- Role of the Board of Trustees (Board or BOT).
- Communications and control.
- Strategic planning.

Corporate governance refers to the processes, systems and associated checks and balances by which a utility is governed and controlled, and includes the relationships and potential conflicts in goals and activities between management and its varied stakeholders.

A. BACKGROUND

LIPA is a Public Authority, governed differently than investor-owned utilities, as discussed in **Chapter II – LIPA Background and Prior Audit**. Rather than a shareholder-elected Board of Directors, LIPA has a government-appointed Board of Trustees. Additionally, nearly all of the traditional core utility services such as system maintenance, procurement, billing, customer service, daily system dispatch and operations are provided to LIPA's customers by a Service Provider. Beginning in 1998, the Authority contracted with KeySpan and then National Grid under a Management Services Agreement (MSA) to provide the majority of the services necessary to serve the Authority's customers. National Grid's contract expired December 31, 2013, and PSEG LI became the Service Provider pursuant to the Operating Service Agreement (OSA).

As a result of the LIPA Reform Act of 2013 (LRA), the terms of the OSA were modified, and PSEG LI now provides service under the Amended and Restated Operating Service Agreement (A&R OSA). The LRA significantly changed LIPA's role and imposed new substantive obligations on any service provider - shifting major operational and policy-making responsibilities for the Transmission and Distribution (T&D) system from LIPA to PSEG LI, including responsibilities for capital expenditures, budgets, and emergency response.

The LRA and the A&R OSA define the respective roles and responsibilities of LIPA and PSEG LI and the extent of LIPA's oversight of PSEG LI. Simply stated, LIPA owns the T&D system assets and associated debt and is responsible for the oversight of PSEG LI. PSEG LI operates the T&D system assets. The LRA further requires that staffing at the Authority be kept at levels only necessary to ensure that the Authority is able to meet obligations with respect to its bonds and notes and all applicable statutes and contracts, and to oversee the activities of the Service Provider.[1] As a result, with the exception of its finance responsibilities, LIPA's organization structure largely focuses on the Service Provider contract oversight/administrative function. In addition to finance responsibilities and oversight of PSEG LI, LIPA is also responsible for conducting wholesale market activities and approval of power and fuel supply contracts per the A&R OSA.[2] **Exhibit III-1** is a high-level overview of the division of responsibilities between LIPA and PSEG LI.

Exhibit III-1
Division of Responsibilities between LIPA and PSEG LI

	LIPA	PSEG LI
Number of Employees	49	2,350
Ownership of T&D System Assets	✓	
Financing and Debt Management	✓	
Reporting	✓	
Oversight of PSEG LI Activities	✓	
Meter Reading		✓
Billing and Collections		✓
Customer Service		✓
Managing Customer Delinquencies / Disconnections		✓
Forecasting		✓
Power Supply		✓ [Note 1]
Wholesale Market Activities	✓	
Approval of Power and Fuel Supply Agreements	✓	
Naming/Branding on Customer Bills		✓

Note 1: PSEG Energy Resources & Trade LLC (PSEG ER&T) also provides power supply and fuel management services, which is overseen by LIPA.
Source: NorthStar analysis, http://www.lipower.org, A&R OSA.

Consistent with the LRA, the Authority's staff was reduced from approximately 100 positions to approximately 50 positions as of May 31, 2014. The Authority's staffing was further reduced to approximately 40 positions when the Power Supply Group was moved to PSEG LI. It also transitioned from Consolidated Edison Energy Incorporated (CEE) and Pace under the Power Supply Management (PSM) operations management to a contract with PSEG ER&T to provide services related to fuel, power supply management and certain commodity activities. LIPA resources now total 49 positions, five of which are characterized as new positions.[3]

The LRA also changed LIPA's governance structure and the composition of the Board of Trustees. **Exhibit III-2** provides LIPA's current governance structure. LIPA is now

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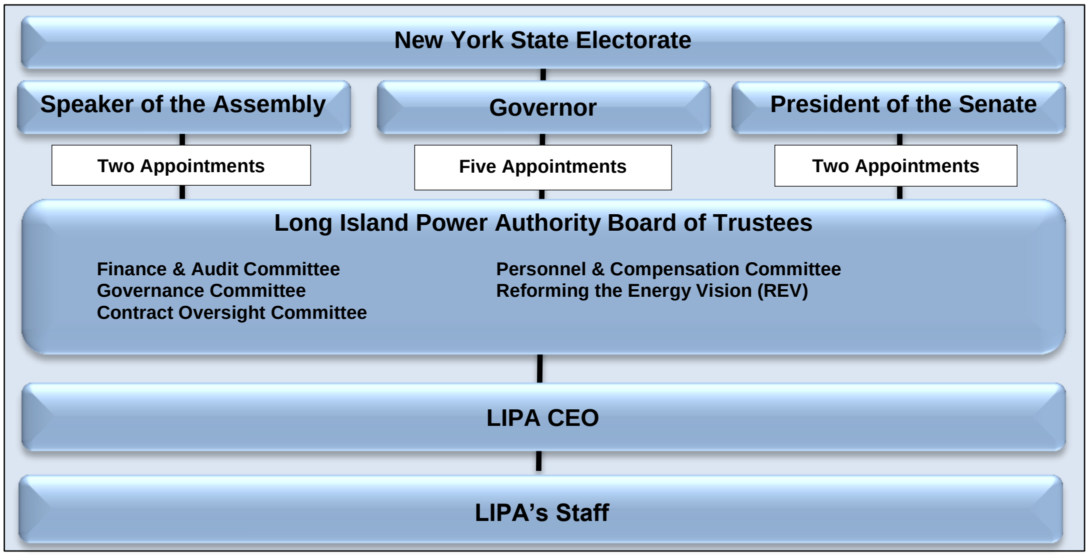
[1] http://www.lipower.org/pdfs/company/papers/LIPAPSEG/LIPABillS5844.pdf - SB 5844, Part A
[2] A&R OSA Section 4.4 and Section 42 (A)(6)(c)
[3] DR 1 Revised Attachment 1

governed by a nine-member Board of Trustees – five appointed by the Governor, two by the President of the Senate and two by the Speaker of the Assembly.[4]

Exhibit III-2
LIPA Governance Structure



Source: DR 1 and http://www.lipower.org

The roles of various groups are as follows:

- **Board of Trustees (BOT)** - According to LIPA's policies, the BOT is responsible for defining the mission, values and strategic direction of the Authority; monitoring performance against polices established by the BOT; adopting annual budgets; setting rates; hiring, evaluating and discharging selected Officers; monitoring staffing levels; approving certain contractual agreements; and, fulfilling its fiduciary responsibilities.[5] The BOT currently has five committees: Contract Oversight, Governance, Finance and Audit (F&A), Personnel and Compensation, and Reforming the Energy Vision (REV).[6]

- **Officers** - The role of the Authority's Officers (i.e., Chief Executive Officer, Chief Financial Officer, and General Counsel) is to make recommendations to the Board; undertake the administrative and operational means necessary (in conjunction with the Service Provider) to achieve defined results; represent the interests of the Authority in regulatory proceedings; finance the business and operations of the Authority; manage legal matters; and hire, evaluate and establish compensation and salary policies for Authority Staff.[7]

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[4] Previously the BOT consisted of 15 members.

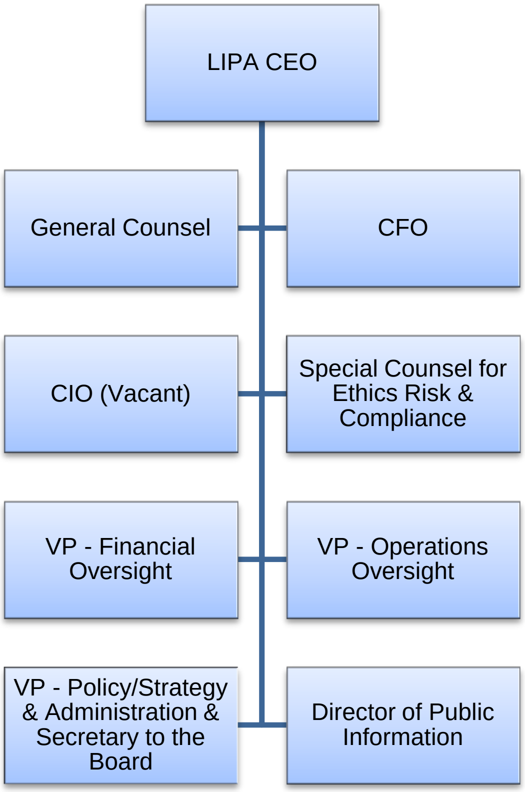
[5] Policy on Purposes and Roles, Resolution 1322, approved September 21, 2016

[6] http://www.lipower.org/profile/trustees.html

[7] Policy on Purposes and Roles, Resolution 1322, approved September 21, 2016

- **LIPA Staff** - LIPA's staff serve three functions: 1) assisting the Board in setting policies and monitoring outcomes relative to the Authority's mission and values; 2) overseeing the Service Provider's implementation of its responsibilities under the A&R OSA, including negotiating mutually agreeable annual performance metrics and incentives for delivering customer value and reasonable budgets to achieve agreed-upon goals; and, 3) managing the internal operations of the Authority (outside of the A&R OSA) in the areas of public policy, finance and risk management, treasury, investor relations, wholesale market activities, legal affairs, internal administration and stakeholder relationships.[8] **Exhibit III-3** provides the LIPA management organization as of January 25, 2018.

Exhibit III-3
LIPA Organization [Note 1]
(January 25, 2018)



Note 1: A Director of Audit reports administratively to the CEO and also the Finance and Audit Committee of the Board of Trustees.
Source: www.lipower.org

- **Service Provider** - The role of the Service Provider is to operate LIPA's T&D system; become the name and face of electric utility service in the LIPA service territory; communicate with public officials, customers, community or industry

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[8] DR 4

groups and the media; report to the BOT as needed; and cooperate with the Department of Public Service (DPS) in its review of the Service Provider's operations.[9]

LIPA's Business Model

LIPA's Business Model is described in its recent Operations and Oversight Plan.[10] The LIPA Board of Trustees sets policies for the utility and ensures its performance on behalf of its customer-owners, including exercising authority over LIPA's rates and charges, hiring and evaluating LIPA's officers, and approving its budgets and major contracts. LIPA's CEO and employees serve as the staff to the Board and perform the operational functions typical of a utility holding company, such as strategic planning, finance and risk management, investor relations, treasury, budgeting, financial reporting, contracting, legal affairs, internal administration, and oversight of the service provider managing day-to-day utility operations of its T&D system.

Since the beginning of 2014, LIPA has contracted with a wholly-owned subsidiary of Public Service Enterprise Group, Inc. (PSEG), a diversified energy holding company and operator of one of the largest investor-owned utilities in the United States – PSE&G in New Jersey - to operate LIPA's electric assets under the PSEG Long Island brand (PSEG LI).[11] The services provided to LIPA by PSEG LI and its affiliates include T&D system management and operations, power supply and fuel supply planning and management, customer service, billing and collections, public and customer communications, business services, information technology and data management, legal services related to operations, facilities management, and other miscellaneous activities.

LIPA's public-private partnership business model provides the cost savings and benefits of public ownership by a locally controlled, not-for-profit utility with the synergies and depth of resources of a large and well-regarded investor-owned utility. Having an experienced operator with a reputational stake and long-term commitment to LIPA's success is a key benefit of LIPA's business model.

Management and Oversight

Given the organizational relationship between LIPA and PSEG LI, a shared vision, mission and goals, and appropriate coordination and communication are critical. The assignment of roles and responsibilities between LIPA and PSEG LI must be clearly defined 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 must be directed and implemented in a coordinated manner, with informed decisions being made at appropriate levels within the organizations. Information regarding key aspects of the operations, performance against

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[9] DR 4 (A&R OSA §4.2)
[10] http://www.lipower.org/profile/mission.html
[11] http://www.ezodproxy.com/pseg/2017/10k/HTML1/pseg-10k2016_0104.htm

goals, pending and rising issues must be relayed on a regular basis and in a manner that allows management to quickly identify trends and monitor progress on projects.

LIPA is organized to reflect its dual role: managing the responsibilities of the Authority, largely as they relate to its financing and debt management requirements and meeting the needs of its stakeholders; and, overseeing the operations of PSEG LI. LIPA's staff is organized in five departments. Two departments have primary responsibility for overseeing PSEG LI and three departments primarily manage LIPA's operations.[12] A Director of Audit and the Special Counsel also report to the CEO. An overview of departmental responsibilities is as follows:[13]

Oversight of PSEG LI

- **Operations Oversight** provides oversight of PSEG LI's utility operations principally through setting and measuring the A&R OSA performance metrics each year; reviewing planning for future capital requirements and generation and transmission needs; overseeing generation resource procurements; reviewing customer service activities; overseeing the customer complaint and customer appeals process; supporting the REV initiatives and other clean energy and state-wide goals; and reviewing storm response consistent with utility best practices and Federal Emergency Management Agency (FEMA) requirements. Operations oversight also manages LIPA's wholesale electricity market activities, including its participation in the development of wholesale market policies by the federal and state governments; and it oversees and directs the PSEG affiliate responsible for managing LIPA's day-to-day power supply, fuel operations, and hedging transactions.

- **Financial Oversight** provides oversight of PSEG LI's utility operations by monitoring procedures and performance for budgeting, revenue forecasting and tracking, reporting of storm costs, meeting FEMA reimbursement guidelines, cost accounting allocations, affiliate charges, PSEG LI's rates, pricing and regulatory functions.

LIPA's Operations

- **Finance** provides debt management, cash management, financial policy, financial reporting, bondholder and rating agency relations, and risk management services to ensure that LIPA maintains access to adequate financial resources and achieves levels of financial performance consistent with the directions established by the Board for fiscal soundness.

- **Legal** provides guidance for all LIPA's operations and contractual arrangements including procurements and tariff interpretations, enforcement of statutory responsibilities under state and federal law (including ethics and standards of

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[12] DR 1

[13] DR 1

conduct), litigation management, and oversight of PSEG LI's litigation and regulatory activities.

- **Executive** provides external focus and global oversight responsibilities over the Authority and PSEG LI with direct responsibility for the execution of all Board policies and specific responsibility for establishing policy and strategy, communicating accurate and insightful public information, and ensuring the independence of the Internal Audit Department.[14] This function is also responsible for human resource and administration activities, and management of all board activities including the role of secretary to the Board.

Strategic Planning

Strategic planning provides a roadmap of the Authority's overall direction, its plan for the future, and how it expects to achieve that future. The Authority's strategic planning process should include identification of industry and economic trends and should be consistent with its risk management process, as well as 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 there are many possible methods that organizations can use to develop quality strategic plans. Whatever methods are used, successful strategic planning processes require clear and strong leadership from both the Executive Management and Board levels, an active process to involve and obtain input from all parts of the organization, an ongoing corporate commitment to the plan and explicit monitoring of progress towards the goals.

Given the unique structure, LIPA's and PSEG LI's long-term strategic planning, shorter-term tactical planning and budgeting activities must be coordinated and consistent. Areas requiring coordination to minimize potential conflicts and achieve optimal performance include:

- Mission and Vision
- Long-term Strategy
- Long-term Integrated Resource Plans (i.e., IRP)
- Planning Criteria
- Tactical Plans
- System Planning
- Prioritization
- Budgeting
- Performance Management.

Both LIPA and PSEG LI perform strategic planning. As described later in this chapter, LIPA recently launched a more defined strategic planning process, the results of which are

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[14] DR 40

reflected in its Three-Year Operations and Oversight Plan. PSEG LI uses a balanced scorecard as the centerpiece for implementing its strategy in the short-term.

LIPA

LIPA's mission is to enable the provision of clean, reliable, and affordable electric service for its customers on Long Island and the Rockaways. The LIPA Board of Trustees aims to achieve excellence in governance in keeping with its important civic responsibility. That begins by defining the mission and values that determine how LIPA serves its community. The LIPA Board has approved several policies intended to clarify its role and responsibilities as fiduciaries, set appropriate governance priorities, and enhance its collective performance as the governing body for our local, publicly owned, not-for-profit electric utility. The Board commits to continue to review and enhance its policies and practices over time to ensure the achievement of LIPA's mission to enable clean, reliable and affordable electric service to LIPA's customers on Long Island and the Rockaways.

In 2016, the LIPA Board adopted a governance model that it believes represents the best practices for public power utilities in the United States and is recommended by the American Public Power Association (APPA) for its members.[15]

- The governance process adopted by the LIPA Board recognizes that it is the role of the Board to set policy and provide specific direction to the Authority on its mission and ends to be achieved in the form of specific policy statements.

- The LIPA CEO develops tactical plans (represented as the goals for the year) in pursuit of the Board-defined policies and reports back to the Board periodically (at least annually) on their attainment.

- The Board reviews the performance of the CEO (who is responsible for the performance and evaluation of the entire LIPA staff and the Service Provider) and may determine whether there is a need to reconsider the goals and policies in light of the CEO's performance.

PSEG LI

Exhibit III-4 provides PSEG LI's Vision and Mission.

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[15] DR 41 and http://www.lipower.org/pdfs/company/papers/board/policies/2017_LIPA_Operations_Overisght_Plan.pdf

Exhibit III-4
PSEG LI's Vision

PSEG LI's strategy is outlined at several levels, beginning with a Vision Statement that is common across the entire PSEG enterprise.

The PSEG Vision

Being a recognized leader for:

People providing
Safe, reliable
Economic and
Greener *Energy*

Below the vision statement is PSEG Long Island's Mission Statement: to build an industry leading electric service company that places safety first, in all we do, providing our customers across Long Island and the Rockaways with:

- Excellent customer service
- Best in class electric reliability and storm response
- Opportunities for energy efficiency and renewables
- Local, caring, and committed employees, dedicated to giving back to their communities

Source: DR 40

The Mission Statement in **Exhibit III-5** is PSEG LI's commitment to employees and customers.

Exhibit III-5
PSEG LI's Mission

PSEG Long Island is committed to providing its employees:

- The tools and training to always work safely.
- A fair and trusting environment where diversity is encouraged, welcomed and valued.
- A workplace that fosters open two-way dialog and listening, where employees feel comfortable speaking up.
- An environment that empowers its employees and nurtures growth through learning experiences and developmental opportunities.
- Open access to the resources needed to effectively complete their assigned responsibilities

PSEG LI is committed to providing its customers:

- Exceptional customer service where employees consistently create a positive customer experience
- A caring and accessible company that is recognized as being fair, honest and responsive
- A good neighbor and trusted and visible community partner
- Helpful, courteous and accountable employees that appreciate and respect those we serve
- A safe and highly reliable electric system

Source: DR 40.

Communication

LIPA and PSEG LI executive management conduct routine meetings to discuss issues and performance.[16] **Exhibit III-6** provides a listing of key joint and separate governance meetings

Exhibit III-6
Key Oversight Meetings

Working Group or Meeting	Purpose
Joint PSEG LI/LIPA	
Management Review Board (MRB)	Address any management issues between LIPA and PSEG LI, per the OSA.
Balanced Scorecard Meeting	Senior management and staff jointly review the monthly balanced scorecard results with PSEG LI
Finance Meeting	Review outstanding or emerging issues between PSEG Finance and LIPA Finance Departments.
IRP/Off Shore Wind Integration Meeting	Discuss the impact of NYS Off-shore Wind Guidelines on the IRP.
Utility 2.0	Discuss progress against Utility 2.0 Plan.
Transmission and Distribution Planning Coordinating Council (TDPCC)	Review operations and planning issues.
FEMA Mitigation Program Meetings	Monitor spending, program compliance and progress toward meeting the requirements of the Letter of Understanding with FEMA.
Northern American Electric Reliability Corporation Northeast Power Coordinating Council, Inc. (NPCC) Compliance meeting	Review compliance with regulations, etc.
NERC Compliance Meeting	
T&D Capital Variance Meeting	
Reforming the Energy Vision (REV) Call	Review progress on REV initiatives including programs and tariff items.
Rate Roadmap Meetings	Meetings to discuss LIPA's pending or future tariff modifications and proposals.
Sales and Revenue Forecasting	
LIPA	
Enterprise Risk Management Committee	Responsible for the commodity hedging, interest rate hedging and enterprise risk management activities of LIPA.
Senior Staff Meeting	Review projects and activities within and across the LIPA departments.
PSEG LI	
Utility Review Board (URB)	Approve capital projects.
Customer One	Discuss the results of PSEG LI's Customer One JD Power related improvement projects.
Capital Budget Review Meetings	Review status of capital budget efforts and spending.

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[16] DR 46

Working Group or Meeting	Purpose
Tariff Review Committee Meeting	Minutes of the meeting are shared with LIPA
LIPA and/or PSEG LI Meetings with DPS	
DPS Status Meeting	Meet with DPS Long Island staff to review the results of the Revenue Decoupling Mechanism and Delivery Service Adjustment calculations, plus any other topics of importance related to LIPA's revenue or rates.

Source: DR 28, 46, LIPA/PSEG LI Fact Verification.

B. EVALUATIVE CRITERIA

Executive Management

- Are the governance, organizational structure, missions and relationships within LIPA and PSEG LI appropriate?
- Are measurable goals, metrics, and key performance indicators used to monitor progress towards achieving the corporate mission and objectives?
- Is the performance improvement process at successive levels of management appropriate? (Addressed in Performance Management)
- Is LIPA's corporate structure sufficiently robust to adequately oversee the provision of electric service to its 1.1 million ratepayers?
- Is the authority exercised by executive management over its service provider, PSEG LI appropriate?
- Are the formal and informal paths of communication among the executives at LIPA and PSEG LI management reasonable and effective?
- Is management's involvement in the strategic and contingency planning processes appropriate?
- Are management performance and compensation programs suitably aligned with the corporate mission, objectives and goals at all organizational levels?
- Are the reports provided to executive management sufficiently useful in monitoring performance, proactively identifying problems and trends, and making defensible decisions?
- Is the working relationship between executive management and the Board of Trustees, including reports shared with the Board and Board committees, appropriate and effective?

Current and Future Organizational Structure

- Are LIPA's major functions suitably structured within the organization to provide quality service to customers and sufficient support to operations?
- 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?
- Does the LIPA/PSEG LI organization ensure that there is efficient utilization of resources, with no duplication of services?
- Does the PSEG LI organizational structure provide clear authority, responsibilities and duties?

- Are the spans of control, lines of responsibility, number of management levels, and staffing levels consistent with good utility operations practices?
- Does the ServCo model represent appropriate spans of control and lines of responsibility, and does it represent lessons learned and improvements over the existing operating structure?
- Has LIPA identified the processes, systems, and controls needed to assure successful implementation of the ServCo business model?

Board of Trustees (Board):

- Is the role of the Board of Trustees and executive and senior management in the development of budgeting guidelines and periodic budget reviews and approvals appropriate? (Addressed in Chapter V - Budgeting and Financial Reporting)
- 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 Board's role in the hiring and evaluation of the performance of the CEO and other executives appropriate?
- Is the composition of the Board's committees consistent with best practices?
- Does the Board properly represent and address the interests of customers and ratepayers in its monitoring of the organization and its decisions?

Communication and Control

- Is an effective process in place to communicate the result of consultant studies, internal audits and other evaluations to executive management and the Board, and to ensure that follow-up action is taken on any noted deficiencies?
- Is executive management provided with sufficient information through reporting systems to enable them to effectively evaluate the extent to which corporate goals and objectives are being achieved?
- Does LIPA have a formalized process to handle customer complaints and inquiries that have not been resolved? (Addressed in Customer Operations Chapter)
- Has LIPA taken measures to ensure that its operations are transparent to key stakeholders?
- Do LIPA's/PSEG LI's policies and practices ensure that its operations are transparent to key stakeholders?

    - Is information provided in a timely manner in response to requests made by DPS?
    - Do customers receive accurate, clear and timely information regarding rate changes?
    - Do key stakeholders, elected officials and customers receive information on major policy decision-making?

Strategic Planning

- 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?
- Is the process used by LIPA to formulate strategies consistent with good practices? Is the overall strategic planning process sufficiently comprehensive in scope and development?
- Has LIPA adequately defined the specific long-range and short-range positions it wishes to occupy and conveyed the information to PSEG LI?
- Has LIPA effectively executed the strategic plan?

  - 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?
  - Is LIPA sufficiently flexible in its decision making in light of actual experiences, changing conditions, and new priorities.
  - Does LIPA use appropriate tools and reports to monitor progress towards its long-term strategic goals?

- Are LIPA's/PSEG LI's physical system plans, tactical operating plans, capital and O&M budgets, and rate consideration linked to it corporate long-term strategic plan?

C. FINDINGS AND CONCLUSIONS

Organization and Oversight

1. **LIPA's organization structure is suitably aligned with its mission. Operational oversight is consistent with the LRA and A&R OSA, LIPA's enumerated responsibilities and available resources. In accordance with the LRA, a Long Island office of the DPS was established to review and make recommendations with respect to the operations of LIPA and/or its service provider.**

   - Under the A&R OSA, LIPA has enumerated contractual options available to oversee activities and manage PSEG LI's performance.

   - In accordance with the LRA, LIPA's reduced its staffing levels, which are now at about 50.

   - As shown in **Exhibit III-3**, two LIPA departments provide primary oversight of PSEG LI: the Operations Oversight Department and the Financial Oversight Department.[17] These two functional areas employ 14 resources as shown in **Exhibit III-7** and **Exhibit III-8**. Other Departments provide oversight related to their functions.

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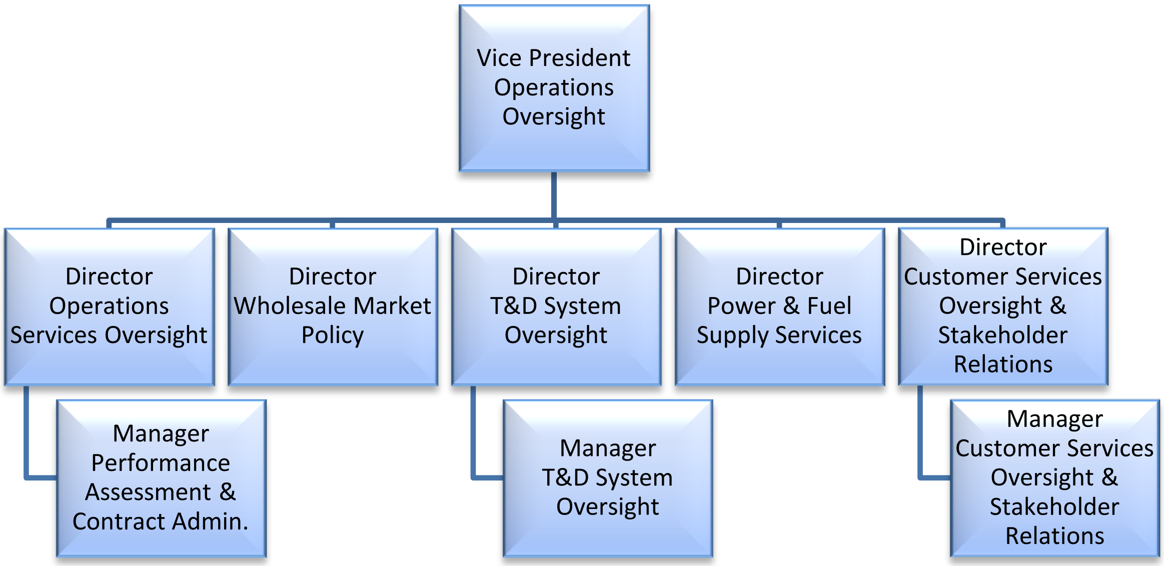
[17] DR 1

- As required by the LRA, a Long Island office of the DPS was established to review and make recommendations with respect to the operations and terms and conditions of service of LIPA and/or its service provider.[18]

Exhibit III-7
LIPA Operations Oversight Organization – As of 2017



Source: DR 1 Revised Attachment 1

- LIPA's Operations Oversight Department monitors PSEG LI's performance in customer service, T&D operations and planning, energy efficiency, and long-term power supply planning and procurement.[19] Reviews and observations include, but are not limited to the following:
  - Review of daily system status and incident reports.
  - Review of data on outages, job dispatch, and restoration time through Outage Management System (OMS).
  - Participation in conference calls with PSEG LI and on-site observation at dispatch and staging areas to review status of system and progress of emergency response activities; after-action reviews; and review of storm invoices for compliance with OSA and FEMA requirements.
  - Review of customer complaints submitted to the Department of Public Service or directly to LIPA and follow-up with PSEG LI, as appropriate.
  - Review of PSEG LI compliance with NERC requirements and approval of submissions to NERC.

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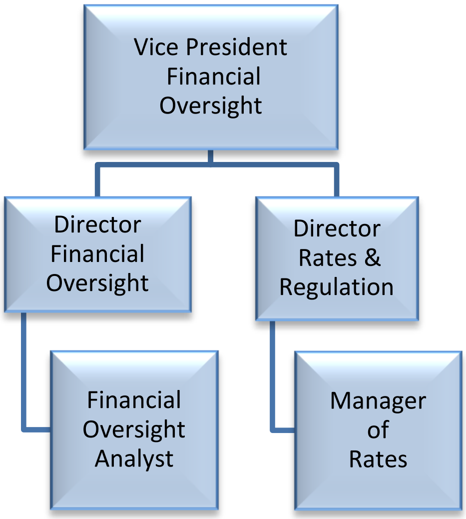
[18] LIPA Reform Act
[19] DR 46

  - Review PSEG LI initiatives relating to Utility 2.0 Long-Range Plan and the Reforming the Energy Vision proceeding.[20]
  - Review progress of FEMA-funded storm hardening program.
  - Attendance at PSEG LI meetings involving T&D system and resource planning; preparation of Request for Proposals (RFPs) for services or power supply; evaluation of proposals for power supply contracts; and review and approval of proposed power contracts and amendments.
  - Review of proposed comments and regulatory filings to the DPS.
  - Review of presentations prepared by PSEG LI to brief LIPA on regulatory or operational matters, contractual issues, customer issues, planned initiatives, etc.
  - Review and approval of environmental assessments for proposed T&D projects in compliance with the State Environmental Quality Review Act.

- The LIPA Financial Oversight (FO) Department shown in **Exhibit III-8** focuses on oversight of financial activity and forecasting, rate making initiatives and implementation, and ongoing budget monitoring participating in meetings, conference calls, e-mail correspondence, and review of reports and work papers. FO also monitors PSEG LI's fiscal condition.

Exhibit III-8
LIPA Financial Oversight Organization



Source: DR 1 Revised Attachment 1

  - FO monitors and reports on the financial operations of PSEG LI. PSEG LI is responsible for budget development, variance tracking and year-end projections specific to its operations.

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[20] Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (referenced as the "Track One Order" or "Framework Order") issued February 26, 2015

  - FO attends the Management Review Board (MRB) meetings to review performance data, and discuss operational and financial issues.
  - FO also participates in monthly Scorecard meetings held jointly with PSEG LI.
  - FO works with PSEG LI to gain an understanding of and monitor the use of affiliates in their operation of the LIPA owned system. Monitoring activities will include a review of monthly charges as prepared by PSEG LI, and periodic review of PSEG LI due diligence with respect to such charges. In addition, FO will work with LIPA internal audit who has engaged outside experts to review and report on the accuracy and appropriateness of such charges.
  - FO determines the effectiveness and efficiency of using affiliates as opposed to alternatives such as outsourcing or staff additions.
  - FO also reviews policies and procedures in many functional areas such as:

    - Release of materials from stores during a declared storm event.
    - Work with PSEG LI to develop capitalization criteria for materials consumed in declared storm events.
    - PSEG LI's Procedures for updating plant records and system maps.
    - PSEG LI's progress in its review of inside plant records.
    - Work with Legal and PSEG LI to undertake a review of the assessed valuations of certain sub stations and the related taxes being paid.
    - Establish Process for Closing Out FEMA Grants
    - Work with PSEG LI to monitor spending needs, forecasted needs of the service provider, anticipated recoveries, and rate adjustment mechanics in order to determine the need for a rate case in to be filed in February 2019.[21]

- LIPA Internal Audit meets with PSEG LI Internal Audit to discuss and review PSEG LI's Internal Audit activities, audit plan, and audit reports.[22] Internal Audit:

  - Discusses the PSEG LI Internal Audit activities, status of audit plan, audit observations and audit follow-up activities.
  - Reviews the status of the PSEG LI Internal Control testing and remediation of Internal Control failures.
  - Reviews PSEG LI Audit Reports for completeness, accuracy, adequacy and timing.
  - Reviews PSEG LI Internal Audit Combined Procedures Reports (Audit Procedures) for sufficiency of audit testing procedures.
  - Reviews PSEG LI Management Action Plan Follow-Up for completeness of follow-up activities performed.

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[21] LIPA/PSEG LI Fact Verification

[22] DR 46, LIPA/PSEG LI Fact Verification

2. **LIPA's oversight of PSEG LI consists of reviewing and overseeing PSEG LI's activities to fulfill its authority under the LRA and A&R OSA.**

    - LIPA and PSEG LI executive management conduct numerous routine meetings to discuss issues and performance.[23] These include:
        - Balanced Scorecard
        - Performance Metrics Evaluation
        - Finance Reports
        - Rate and Tariff Scorecard
        - Management Review Board
        - Utility Review Board

    - Each month, LIPA and PSEG LI conduct a Balanced Scorecard meeting at which PSEG LI presents its operating results and performance associated with all of the Tier 1 and Tier 2 metrics and related information. PSEG LI management and staff respond to performance issues or matters requiring further investigation by PSEG LI or LIPA. Annually, LIPA reviews PSEG LI's performance under the Tier 1 metrics, for purposes of determining its annual incentive compensation.

    - LIPA and PSEG LI senior management also meet as the Management Review Board, as specified in the OSA, to discuss policy matters or performance issues that have not been resolved at the staff level.

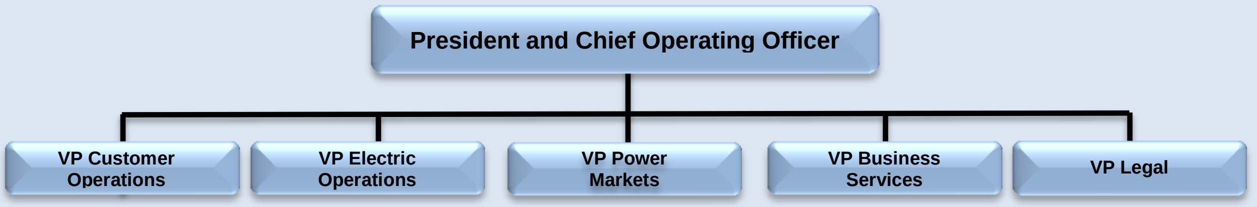
    - An important example of management coordination is determination of the need for a 2019 rate case. LIPA and PSEG LI have met several times at the staff level and the Senior Leadership Teams to discuss and review this subject.

3. **LIPA's lean resources and oversight role versus PSEG LI's operations role effectively precludes duplication of services.**

4. **The PSEG LI organization is appropriate, reflecting its major areas of responsibility under the A&R OSA.**

    - **Exhibit III-9** provides PSEG LI's current organization structure.

Exhibit III-9
PSEG LI Organization



Source: DR 830.

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[23] DR 46

- PSEG LI re-organized its operating structure below the levels shown above in **Exhibit III-9**, in the fall of 2017. A presentation of the new structure was given to LIPA staff on September 7, 2017.[24] Implementation was scheduled for late 2017 and early 2018. PSEG LI's organizational changes were intended to:

  - Promote leaders who have achieved extraordinary results and demonstrated commitment to company's core commitments, diversity and inclusion
  - Increase leadership in critical areas
  - Increase ownership, decision making ability, and teamwork at lower levels of the organization
  - Position organization for continuous improvement and embrace change
  - Promote and encourage new ideas.

- Highlights of the new organization include the following:

  - Implement Division Model – an East and West Division will include:

    - Distribution Operations
    - Overhead and Underground Construction
    - Distribution Engineering
    - Substation Field Maintenance and Protection

  - T&D Services and Projects and Construction move to Business Services. Projects and Construction include project management and construction management. A Project Management Office will include Estimating, Planning and Risk, Cost and Schedule, and Permitting.
  - Increase Leadership focus in Projects and Construction
  - Project Management Office
  - Projects and Construction
  - Consolidate several operating functions into one new department; Training, Support and Contractor Services
  - Promotions and rotations in Customer Operations
  - Transfer of certain duties from T&D to Power Markets.

- PSEG LI organizations that were not re-structured include:

  - Business Services
  - Customer Operations
  - Asset Management
  - Legal
  - Power Markets
  - Planning, Resources and Engineering.

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[24] DR 830 and 832

- During the reorganization effort, PSEG LI reiterated that safety remained its primary priority along with system reliability and customer service.[25]

- PSEG LI uses informal guidelines with respect to managerial spans of control reporting relationships. The spans listed below are used as guidelines and vary depending on multiple factors some including organizational size, nature of work, workforce skill level, organizational culture, and manager responsibilities.[26] PSEG LI uses different span of control ranges at different levels of the organization:

  - Vice President – 1:4–1:6
  - Director – 1:4 – 1:6
  - Manager – 1:6 – 1:10
  - Supervisor – 1:10 – 1:20

5. **Formal and informal paths of communication among the executives of LIPA and PSEG LI appear reasonable and effective.**

- Communication and coordination among LIPA and PSEG LI is generally a continuous and participative process highlighted by the following.[27]

- LIPA Operations Oversight monitors PSEG LI's performance in customer service, T&D operations and planning, energy efficiency, and long-term power supply planning and procurement. In addition to the numerous PSEG LI reports and materials reviewed, LIPA/PSEG LI formal meetings include:

  - Utility 2.0 Long Range Plan meetings
  - FEMA-funded Storm Hardening Program review
  - Transmission and Distribution Planning Coordinating Council (TDPCC) meetings
  - Monthly Balanced Scorecard meetings
  - Management Review Board meetings.

- NorthStar's observations of the management process, coordination and general communication among the executives at LIPA and PSEG LI were limited as access to management meetings was not provided until very late in the audit. Any NorthStar findings or impressions of LIPA/PSEG LI executive management and its transparency must therefore be qualified as such.[28]

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[25] DR 830

[26] DR 982

[27] DR 46

[28] Email from LIPA Special Counsel to DPS May 8, 2017.

Board of Trustees

6. The LIPA Board has improved since the LRA, but faces the dilemma most boards of public power agencies face; how to expand the level of utility or energy industry experience consistent with an organization of LIPA's size, complexity and revenues.

- The LRA requires that all trustees have relevant utility, corporate board or financial experience.

- Typical practice for Board composition 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.[29]

- The professional backgrounds of the current LIPA Board members are shown in **Exhibit III-10**. Currently, the Board has one member with utility management experience, two members each with experience in local government, and real estate, and one Board member each with a law degree, health care, transportation, and scientific research experience.

Exhibit III-10
LIPA Board of Trustees Background – As of January 8, 2018

Trustee	Professional Background
Ralph V. Suozzi, Chairman	Television and American Express executive, City Mayor
Thomas J. McAteer, Vice Chairman	Transportation, health care executive and not-for-profit Boards
Elkan Abramowitz	Attorney
Sheldon L. Cohen	Real estate and local government
Matthew C. Cordaro, Ph.D.	Utility industry executive
Mark Fischl	Real estate consulting and advisory
Peter J. Gollon, Ph.D.	Scientific research
Jeffrey H. Greenfield	Insurance executive
Drew Biondo	Communications and government

Source: http://www.lipower.org/profile/trustees-bios.html

- Trustee biographical summaries demonstrate backgrounds leading financially successful organizations in both the private and public sectors. They have less experience in the areas of finance, accounting, customer service or corporate boards.[30]

- In addition to the need for relevant experience, Trustees must be committed to a substantial workload to understand the complex issues LIPA faces and to develop a thorough understanding of the environment and technical challenges facing an electric utility of LIPA/PSEG LI's size.

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[29] NorthStar analysis

[30] http://www.lipower.org/profile/trustees-bios.html

7. The Board has recently participated in the development and approval of Authority policy decisions.

- The purpose and role of the BOT is defined in Board Resolution #1323, approved September 21, 2016. In accordance with this policy, the BOT is responsible for identifying and defining the mission, values, and strategic direction of the Authority, including the quantitative and qualitative results that the Authority is to achieve, and communicate them in the form of policy.[31]

- Under the recently adopted APPA-recommended governance model, the utility's strategic direction is developed through a series of "Policy Statements". In accordance with this new governance model, LIPA develops and recommends policy decisions, and the Board approves them. On an annual basis, LIPA reports to the BOT regarding its progress against the goals outlined in the Policy Statements.

    - LIPA's broad objectives are described in the four policy statements supporting its mission to enable clean, reliable, and affordable electric service, shown in **Exhibit III-11**.

Exhibit III-11
LIPA's Mission-Related Goals (as defined in Board Policies)

Policy	Date	Goals
Resource Planning, Energy Efficiency and Renewable Energy	July 26, 2017 (Res. 1372)	• Planning and maintaining a power supply portfolio that meets New York Independent System Operator (NYISO), NYS Reliability Council requirements, environmental standards and the State's Clean Energy Standard (CES). • Managing the power supply portfolio to minimize cost and maximize performance. • Minimizing costs through competitive procurement. • Procuring cost-effective renewable resources. • Representing the interested of LI customers to minimize costs. • Integrating cost-effective distributed energy resources and storage technology. • Updating the Integrated Resource Plan (IRP) no less than every five years.
Customer Service	July 26, 2017 (Res. 1370)	• Funding cost-effective initiatives and ongoing operations to provide customers with a level of service, as measured by industry standard customer service metrics (by 2018) and customer satisfaction surveys (by 2022), within the first quartile of peer utilities. • Protect customer information. • Support customer education programs. • Clearly communicate accurately and proactively.
T&D System Reliability	July 26, 2017 (Res. 1371)	• Comply with applicable regulations. • Fund cost-effective programs to maintain first quartile reliability among New York utilities as measured by System Average Interruption Duration Index. • Fund cost-effective reliability for each customer that is within reasonable variance from system average conditions (i.e., worst performing circuits). • Fund cost-effective programs for resiliency.

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[31] Board Policy: Purpose and Roles (DR 30)

Policy	Date	Goals
		• Use smart grid technologies.
Competitive Rates	September 21, 2016 (Res. 1318) Amended March 29. 2017 (Res. 1357)	• Electric rates should be set at the lowest level consistent with sound fiscal and operating practice, ensuring quality service efficiently rendered. • Electric rates should be competitive with the published rates on a system average basis of other regional utilities that surround the Authority's service territory and most closely resemble the costs and power/gas supply options of the Authority, taking into account the significant differences in the taxing and regulatory regimes in which these utilities operate. • Changes in rates and bills should be competitive in the long term. • Rates should be simple and easy to understand, equitably allocate costs across and within customer classes, taking into consideration the cost to provide service; be affordable by people with low incomes and severe medical conditions; and where possible, be consistent with statewide policies. In addition, in order to promote the goals of Reforming the Energy Vision, rates should reflect the marginal cost of service, to the extent consistent with the foregoing objectives.

Source: www.lipower.org

- Following the adoption of the mission-related Policy Statements, the Board adopted a number of Operating, Governance and Compliance Policies, as summarized in **Exhibit III-12.** provides a listing of Operating, Governance and Compliance Policies adopted since September 2016.

Exhibit III-12
BOT-Adopted Operating, Governance and Compliance Policies
(As of December 31, 2017)

Role/Function	Number of Policies	Policy List
Board Operating Policies	10	• Staffing and Employment (January 25, 2017) • Development, Retention and Succession (September 21, 2016) • Enterprise Risk Management (March 29, 2017) • Economic Development (March 29, 2017) • Investment Policy (March 24, 2017) • Power Supply Hedging Program (March 29, 2017) • Undergrounding Policy (September 27, 2017) • Debt and Credit Markets (September 21, 2016 amended March 29, 2017) • Taxes, PILOTs and Assessments (September 21, 2016) • Safety (September 27, 2017)
Board Governance Policies	7	• Purpose and Role of LIPA Trustees (September 21, 2016) • Governance and Agenda Planning (September 21, 2016) • Trustee Communications Policy (December 20, 2016) • Audit Relationships (March 29, 2017) • By-Laws (amended December 20, 2016) • Committee Charters (updated annually) • Code of Ethics and Conduct – Trustees (March 29, 2017)

Role/Function	Number of Policies	Policy List
Board Compliance Policies	6	• Prompt Payment (March 29, 2017) • Property Disposition (March 29, 2017) • Real Property Acquisition (March 29, 2017) • Lobbying (March 29, 2017) • Procurement (March 29, 2017) • Interest Rate Exchange Agreements (March 29, 2017)

Source: www.lipower.org/profile/mission.html

8. The dynamics and working relationship between the Board and executive management have improved since the prior LIPA Management and Operations Audit in 2013.

- Pursuant to the LRA, on January 1, 2014, the membership of the Authority's Board of Trustees was reduced from fifteen to nine.

- Materials provided to the Board are numerous, complex and require insightful understanding of utility issues. Offsetting these factors, many documents contain only minor changes from earlier versions and some documents relate only to members of certain committees. Responses to NorthStar's data requests show that over 750 documents including formal reports, meeting minutes and updates were provided to the Board from 2014 through 2016. This translates into more than 40 documents to be reviewed by Board members for each Board meeting.[32] These levels underscore the need for Board members to be committed to a heavy workload.

- Trustees do not receive compensation for their time, but are entitled to reimbursement for reasonable expenses in the performance of their duties.[33]

9. The Board's level of involvement in decision making is focused on oversight and approval. The Board should continue to evaluate what is the suitable level of involvement for it to provide to the organization.

- NorthStar interviewed seven of the nine trustees. The interviewed Trustees characterized their role as oversight and supporting LIPA management, rather than "leading" the utility. LIPA Staff prepare materials for Board action and brief Board members. LIPA and PSEG LI make presentations to the Board. Decisions are often made with minimal discussion during Committee and BOT meetings.[34]

- As discussed in Conclusion 7, since 2016, the Board has adopted a number of policies to define its purpose and role, relying on LIPA Staff for their development.

  - The Board adopted over a dozen Board Policies in 2017.
  - All Board Committee charters were updated and adopted during 2017.

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[32] DR 13, 14, 16 and 411

[33] LIPA Reform Act

[34] BOT interviews

- Each of the policies were presented at the Board Committee level and passed to the full Board for adoption.
- Board Committees meet in the morning, prior to the full Board and normally last less than one hour. In some cases, Committees met for only a few minutes. NorthStar could not determine if these were meetings that were simply called to meet a statutory requirement or if the substance discussed was very brief perhaps just an update requested by a Trustee.
- Policies, charter updates, and agreements requiring Board approval are provided to the Committees in the form of Recommendations for Approval or Consideration of Approval by LIPA.[35] Issues requiring a vote are then generally passed to the full Board.

- The degree to which the Board exercises authority and responsibility may be measured in part by its activity level. LIPA's Board activity is comparable to other public boards, but is relatively low compared to boards of large investor-owned utilities.

  - The BOT meets only six times per year plus a Board Development & Educational Workshop in June, and a Board Budget Workshop in November. BOT meetings are one-day sessions and include Board Committee meetings on the same day.[36]
  - The public sessions of the full Board meetings span roughly two to three hours, including public comment. The Board meets in executive session following the public meeting.
  - BOT committees met 3 to 6 times per year on the same day as the full Board during CY 2017, as shown in **Exhibit III-13**.

Exhibit III-13
2017 BOT Committee Meetings

Committee	Number of Meetings
Finance and Audit	6
REV	6
Oversight	5
Governance	4
Personnel & Compensation	3

Source: http://www.lipower.org/profile/trustees-documents.html

- The Authority utilizes the Consent Agenda thereby shortening the duration of the full Board meeting and focusing the discussion agenda on those items most warranting discussion. Any individual Board member has the ability to move items from the Consent Agenda to a full discussion. Consent items are part of the full board agenda and the public has the opportunity to speak on consent items. During the course of

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[35] DR 14 and 16 - various Attachments

[36] http://www.lipower.org/newscenter/events.html

meetings observed by NorthStar some significant policy issues were addressed as Consent Items.[37]

- During CY 2017, Consent Agenda items included:
  - Adoption of minutes from prior BOT meetings.
  - Board Committee Charter revisions.
  - Adoption of Board Policies and revisions.
  - Selection of key service providers, consultants and financing issues.
  - Approval of power purchase agreements.
- It is not clear where or when the Consent Agenda items are discussed by Board Trustees that do not attend specific Committee meetings.

10. Certain Trustees continue to serve although the terms of service have officially expired.

- In accordance with the LRA, trustees serve staggered terms. Initial trustees were to begin service on January 1, 2014. At the time of this audit, three of the Trustees were continuing to serve although their terms had expired, and three more had terms that expired at the end of 2017. Only two Board member's terms extended beyond December 31, 2017.[38]
- In accordance with the Public Officer's Law:

> § 5. Holding over after expiration of term. Every officer except a judicial officer, a notary public, a commissioner of deeds and an officer whose term is fixed by the constitution, having duly entered on the duties of his office, shall, unless the office shall terminate or be abolished, hold over and continue to discharge the duties of his office, after the expiration of the term for which he shall have been chosen, until his successor shall be chosen and qualified; but after the expiration of such term, the office shall be deemed vacant for the purpose of choosing his successor. An officer so holding over for one or more entire terms, shall, for the purpose of choosing his successor, be regarded as having been newly chosen for such terms. An appointment for a term shortened by reason of a predecessor holding over, shall be for the residue of the term only.

- Trustee interviews indicated that there was uncertainty over whether their own terms of service on the Board would be extended as well as the terms of other Board members.

11. The LIPA Board Committee structure is similar to major public utilities.

- Board Committees and membership is shown in **Exhibit III-14**. The Board has five committees.

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[37] NorthStar presence at LIPA Board meetings

[38] DR 987

  - Finance & Audit, Personnel & Compensation, and Governance are typical board committees.
  - The Contract Oversight committee is appropriate given the Service Provider model. Many utility Boards include comparable Operations Oversight Committees.
  - A REV Committee is appropriate given its significance to future utility operations.

Exhibit III-14
LIPA Board of Trustees Committee Assignments

Trustee	F&A	Personnel & Comp.	Contract Oversight	Governance	REV
Ralph V. Suozzi, Chairman					
Thomas J. McAteer, Vice Chairman		Chair		✓	✓
Elkan Abramowitz	✓		Chair		
Sheldon L. Cohen	Chair		✓		✓
Matthew C. Cordaro, Ph.D.		✓	✓		✓
Mark Fischl				Chair	Chair
Peter J. Gollon, Ph.D.					✓
Jeffrey H. Greenfield		✓			
Drew Biondi [Note 1]					

Note 1: Vacant from October 2017 to January 8, 2018.
Source: http://www.lipower.org/profile/trustees-bios.html

- Most Board Committees have three members, one of which is the Committee Chair. The REV Committee has five Trustee members.

- For any committee appointed by the Chair or Trustees, the Chair shall be an ex-officio member who has the right, but not the obligation, to participate in the proceedings of the committees and vote on any action to be taken. Such ex- officio membership shall not, however, be counted for purposes of determining whether a quorum of the committee exists, but the Chair's vote shall be counted in determining whether a proposed committee action has been approved or disapproved by the requisite vote.[39]

- Committee agenda topics pertain to their charter scope and include:

  - Annual performance reports and activity updates.
  - Charter amendments and revisions.
  - Financial reports and Audit activities (F&A).
  - Board Policy.
  - Performance metrics and updates.
  - Budgets.
  - Emergency response and summer preparation.

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[39] LIPA By-Laws

- REV Committee meetings are usually brief (less than 30 minutes). Agenda topics covered during 2017 include:[40]

    - Revisions to the Committee Charter.
    - Update on Interconnection Portal.
    - Discussion of PSEG LI's Utility 2.0 Filing.
    - Plans for Addressing Load-constrained Areas.
    - Consideration of Dynamic Load Management and Street Lighting Tariffs.
    - Selections in Renewable Requests for Proposals and FITs III and IV.
    - Presentation of the Annual Energy Efficiency Report.
    - Value of Distributed Energy Resources and Time-Based Pricing.

12. The results of consultant studies, internal audits, operating performance and status reports are routinely provided by LIPA and PSEG LI executive management to the Board via Committee meetings.

- Audit reports include a management distribution list and the Board Finance and Audit Committee receives summary briefings.[41]

- LIPA and PSEG LI executives provide reports and briefings to Board Committees as described above.

- LIPA's Director of Audit meets with the Finance and Audit Committee in Executive session at least twice yearly to review the Internal Audit Reports outside the presence of LIPA or PSEG LI staff.

13. The Board's role in the hiring and evaluation of the CEO and other executives is appropriate and consistent with industry practice.

- According to the by-laws, the CEO, Chief Financial Officer (CFO) and General Counsel are selected by the Trustees. The CEO appoints the Secretary and Controller and other officers as appropriate. Any officer elected by the Trustees may be removed by the Trustees at any time, with or without cause.[42]

    - John McMahon joined LIPA in April 2013 as COO and became CEO months later. He announced his resignation on April 29, 2015. Prior to that the CEO position was vacant since September, 2010.[43]
    - On March 21, 2016, the Personnel and Compensation Committee recommended that the Board approve a resolution appointing Thomas Falcone as CEO of LIPA, following a search initiated in April 2015.[44] Falcone had been CFO of LIPA since January 2014.

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[40] http://www.lipower.org/profile/trustees.html - Board Meeting and Committee Materials
[41] DR 35, 36 and http://www.lipower.org/profile/trustees-documents.html - Board and Committee Materials.
[42] By-Laws of the Long Island Power Authority, as amended December 20, 2016 (DR 30)
[43] LIPA News Release August 26, 2010
[44] DR 15 Attachment Personnel and Compensation Materials to BOT 2013 2014 2015 2016, DR 31

  - On May 18, 2016, the Personnel and Compensation Committee recommended that the Board approve a resolution appointing Joseph Branca as LIPA CFO, based on the recommendation of the CEO.[45] The Board approved the resolution.

- The Board's role in the hiring and CEO performance evaluation is covered in the Staffing and Employment Board Policy: The Authority's Board of Trustees appoints and, when necessary, discharges the CEO, evaluates the CEO performance and determines compensation, and with the CEO's advice appoints other Board-appointed Officers.

- The Personnel and Compensation Committee of the Board has the following responsibilities:[46]

  - Recommend to the Trustees the compensation of the CEO, CFO and General Counsel.
  - Monitor and make recommendations related to staffing needs and employment policies and procedures.
  - Annually establish and present to the Board the performance goals and objectives for the CEO, General Manager, CFO and General Counsel.
  - Coordinate and review the annual performance evaluation of the CEO, General Manager, CFO and General Counsel.

- A self-assessment is prepared by the CEO and circulated to the members of the Personnel & Compensation Committee and other Trustees.[47] The CEO Performance Evaluation is completed by the Chair of the Personnel & Compensation Committee in coordination with other members of the Committee and submitted to the Chairman of the Board for approval.[48] The evaluation is discussed with the CEO in Executive Session.[49] The CEO is evaluated in accordance with LIPA's mission and associated policies.[50]

- The CEO reviews the performance of the CFO and General Counsel, and provides his assessment to the Personnel & Compensation Committee.

- NorthStar reviewed the goals of the CFO, General Counsel and Secretary, Controller and found them to be consistent with the mission and goals of the organization.[51] 2016 goals had associated measurements.[52]

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[45] DR 15 Attachment Personnel and Compensation Materials to BOT 2013 2014 2015 2016, DR 15 Attachment 108

[46] By-Laws of the Long Island Power Authority, as amended December 20, 2016, Personnel and Compensation Committee Charter (DR 30)

[47] DR 11 and 1000 Attachment 1 - CONFIDENTIAL

[48] Compensation Committee Board Materials (DR 15)

[49] DR 11

[50] DR 11 Attachment

[51] DR 12

[52] DR 12

- NorthStar did not attend any Committee Meeting Executive Sessions. However, the performance goals are consistent with the LIPA goals and the function of the executive officer positions.[53]

Strategic Planning

14. LIPA has suitably defined the mission of the organization. Its purpose is largely defined through various laws and regulations.

- LIPA was established in 1986 by the Long Island Power Authority Act, which was enacted to control electricity costs within the service area of the Long Island Lighting Company (LILCO).[54] LIPA's enabling statute required that it provide safe and adequate service at lower rates, restore confidence, and protect the interests of ratepayers and the economy in the service area.[55]

> § 1020-a. Declaration of legislative findings and declarations
>
> For all the above reasons, a situation threatening the economy, health and safety exists in the service area.
>
> Dealing with such a situation in an effective manner, assuring the provision of an adequate supply of electricity in a reliable, efficient and economic manner, and retaining existing commerce and industry in and attracting new commerce and industry to the service area, in which a substantial portion of the state's population resides and which encompasses a substantial portion of the state's commerce and industry, are hereby expressly determined to be matters of state concern within the meaning of paragraph three of subdivision (a) of section three of article nine of the state constitution.
>
> Such matters of state concern best can be dealt with by replacing such investor owned utility with a publicly owned power authority. Such an authority can best accomplish the purposes and objectives of this title by implementing, if it then appears appropriate, the results of negotiations between the state and LILCO. In such circumstances, such an authority will provide safe and adequate service at rates which will be lower than the rates which would otherwise result and will facilitate the shifting of investment into more beneficial energy demand/energy supply management alternatives, realizing savings for the ratepayers and taxpayers in the service area and otherwise restoring the confidence and protecting the interests of ratepayers and the economy in the service area. Moreover, in such circumstances the replacement of such investor owned utilities by such an authority will result in an improved system and reduction of future costs and a safer, more efficient, reliable and economical supply of electric energy. The legislature further finds that such an authority shall utilize to the fullest extent practicable, all economical means of conservation, and technologies that rely on renewable energy resources, cogeneration and improvements in energy efficiency which will benefit the interests of the ratepayers of the service area.[56]

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[53] NorthStar Analysis (DR 12, Operations and Oversight Plan 2017-2019)

[54] The LIPA Act

[55] https://www.osc.state.ny.us/reports/pubauth/lipa_by_the_numbers_10_2012.pdf

[56] The LIPA Act

- The LRA signed in July 2013, further refined LIPA's purpose. The Reform Act reorganized LIPA, placed day-to-day utility operations under the responsibility of its contractor, PSEG LI, created a Long Island office of the DPS and revamped LIPA's/PSEG LI's electric operations work towards the continual goals noted below.[57] The roles and responsibilities of the Long Island office of the DPS are discussed in further detail in Chapter II.

    - Improving customer service
    - Enhancing emergency response and preparation
    - Reducing the cost of LIPA's debt
    - Ensuring safe and adequate service at rates consistent with sound fiscal operating practices.

- LIPA's mission is to enable clean, reliable, and affordable electric service for its customers on Long Island and the Rockaways.[58] In September 2016, the LIPA BOT approved the following organizational values which are typical of a utility.[59]

    - **Responsiveness:** being attentive to the needs and expectations of our community and stakeholders.
    - **Excellence:** continually innovating and improving upon our performance.
    - **Integrity:** conducting our affairs in an ethical and transparent manner.
    - **Stewardship:** ensuring our assets are utilized efficiently and in accordance with sound fiscal and operating practices.
    - **Sustainability:** minimizing our impact on our natural environment.
    - **Teamwork:** respecting diverse viewpoints and attracting and retaining talented employees.

15. LIPA has made significant improvements in its strategic planning process.

- Until recently, LIPA's strategic planning process was the annual identification of goals at the Authority and Department-level. In general, these were limited, shorter-term goals, which often were insufficiently defined and/or lacked specific targets.[60] General accomplishments against the goals were reported to the Board annually.

- As previously discussed, in 2016 the LIPA Board adopted the APPA-recommended governance model and developed governance policies that define the direction of LIPA, and are considered key elements of LIPA's strategic planning process. These policies address:

    - Resource Planning, Energy Efficiency and Renewable Energy
    - Customer Service
    - T&D Reliability

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[57] http://www.lipower.org/pdfs/company/papers/LIPAPSEG/LIPABillS5844.pdf

[58] http://www.lipower.org/profile/mission.html

[59] Board Resolution #1317, approved September 21, 2016, www.lipower.org

[60] NorthStar Review of DR 44 and Attachments

- Competitive Rates.

- Also, in 2016, LIPA adopted a more formal approach to strategic planning which is consistent with standard practices. LIPA staff prepared the Operations and Oversight Plan for 2017-2019. This plan identifies the significant new initiatives to be undertaken directly by the LIPA staff, as distinguished from PSEG LI over the next three years. In essence, it is LIPA's business plan.

- In developing its Operations and Oversight Plan, LIPA performed a situational analysis (strengths, weaknesses, opportunities and threats (SWOT) analysis and defined six over-arching priorities:[61]

  - Investing in the reliability of Long Island's electric grid
  - Enhancing customer service and value
  - Promoting affordability
  - Building a clean energy future
  - Transitioning to a 21st century utility
  - Exercising fiscal responsibility and maximizing the benefits of public ownership.

- The Plan identifies initiatives to be undertaken directly by LIPA associated with these six priorities, with specific department goals and accountabilities.

- The situation analysis (SWOT) appropriately reflects LIPA's strengths and weaknesses. Threats and opportunities are reflective of LIPA's operations and operating environment.[62] The SWOT analysis reflects an understanding of where the organization is now, who its customers are, and where it needs to be in the future. LIPA plans to perform the SWOT analysis on an annual basis.[63]

- As currently envisioned, LIPA's strategic planning process will incorporate appropriate long-term, mid-term and short-term elements shown in **Exhibit III-15**. As some of these elements had not been completed at the time of the audit, NorthStar did not fully assess linkages.

Exhibit III-15
Components of LIPA's Strategic Planning Process

Component	Update Frequency	Responsible Parties	2017 Status	Notes
Long-Term (5-20 Years)				
Board Policies	Annually	LIPA Board and Management	Complete	Adopted in 2016 and 2017. Additional policies may be adopted in the future.
15-Year Financial	Annually	LIPA & PSEG	In process	Plan was to finalize after IRP. Not

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[61] Operations and Oversight Plan 2017-2019 (DR 40)
[62] NorthStar Analysis, Operations and Oversight Plan 2017-2019 (DR 40)
[63] DR 244

Component	Update Frequency	Responsible Parties	2017 Status	Notes
Plan		LI Management		completed at time of audit.
Integrated Resource Plan	Every 3-5 years. Sooner if needed	LIPA & PSEG LI Management	Complete	Draft IRP released in 2017. Staff IRP recommendations approved at the July 2017 Board Meeting.
Medium-Term (2-5+ Years)				
Multi-Year PSEG LI Improvement Metrics	Annually	LIPA & PSEG LI Management		Discussed in Chapter XIII.
Three-Year Rate Cases	Generally, every 3 years	Board, LIPA & PSEG LI Management		
Five-Year Budget Forecast	Annually	LIPA & PSEG LI Management		
Three-Year Operations and Oversight Plan	Annually	LIPA Management	Complete	First Operations and Oversight Plan covers 2017-2019.
Rate Roadmap	Annually	LIPA & PSEG LI Management	In process	Being developed during 2017. Expanded in May 2018.
Short-Term (Annual)				
Annual Budget	Annually	Board, LIPA & PSEG LI Management	Complete	
Annual PSEG LI Metrics	Annually	LIPA & PSEG LI Management	Complete	Discussed in Chapter XIII
Annual LIPA Employee Performance Goals and Evaluations	Annually	Board and LIPA Management	Complete	
Feedback Mechanisms				
CEO Performance Evaluation	Annually	Board and LIPA Management		
Annual Reports on Board Policies	Annually	Board and LIPA Management	Complete	Seven completed in 2017 based on new policies. According to LIPA, all reports that were due were completed.
Achievement of PSEG LI Tier 1 and Tier 2 Metrics	Annually	LIPA & PSEG LI Management	Complete	Discussed in Chapter XIII.
Enterprise Risk Management Program	Annually	LIPA & PSEG LI Management	In progress	Recommendation from prior audit. Still under development.
SWOT Analysis	Annually	LIPA & PSEG LI Management	Complete	

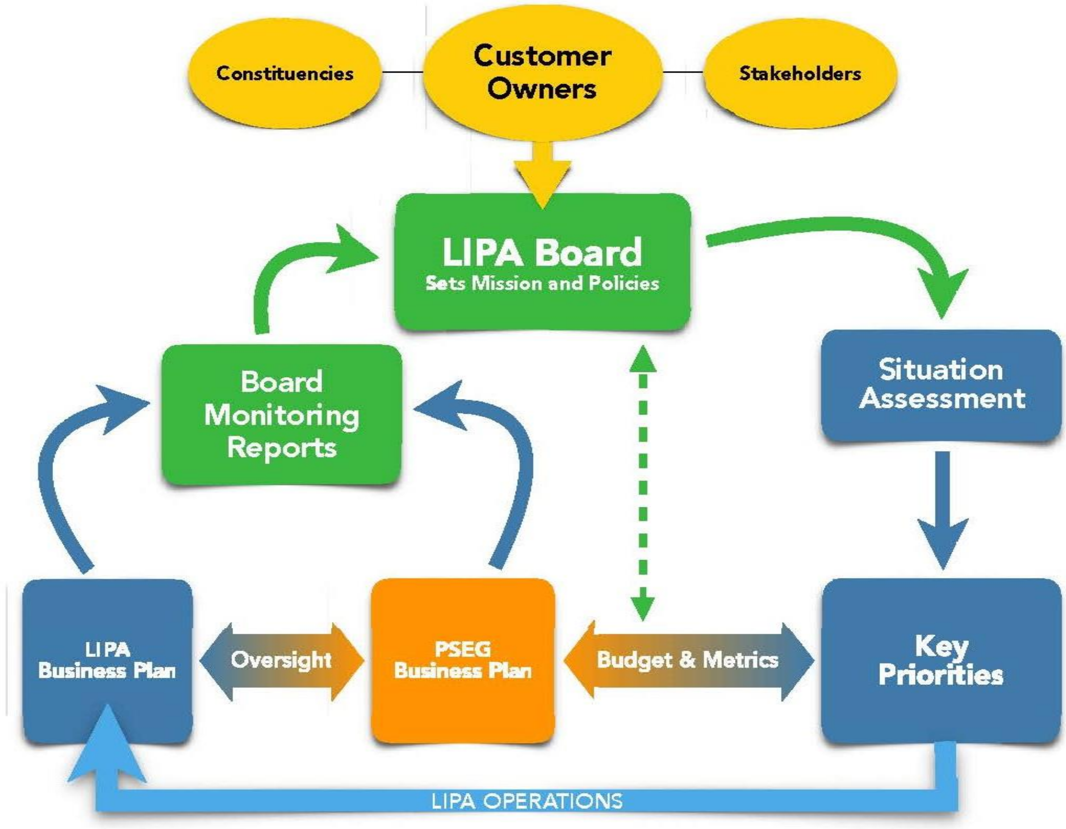
Source: DR 244, LIPA/PSEG LI Fact Verification.

- The strategic planning process appropriately considers LIPA's operating environment and key stakeholders including regulators, the financial community and customers. As shown in **Exhibit III-16**, LIPA's/PSEG LI's physical system plans, tactical operating plans, capital and O&M budgets, and rate consideration are linked to the corporate long-term strategic planning process.

16. **LIPA has adequately defined its specific long-range and short-range objectives and conveyed the information to PSEG LI, for inclusion in its plans.**

- The planning process links the objectives of LIPA and PSEG LI, as shown in **Exhibit III-16**.

Exhibit III-16
Overview of the Business Planning Process



Source: Operations and Oversight Plan 2017-2019 (DR 40).

- In accordance with Public Authorities Law Section 1020-f(ee) and the A&R OSA, on July 1, 2014, PSEG LI submitted its first Utility 2.0 Plan Long Range Plans for approval by LIPA and review by the DPS.[64] Updates have been submitted annually. DPS solicits public comments on the annual plans.[65] To implement its strategy PSEG LI develops initiatives and a balanced scorecard for assessing performance that ties to its vision and includes the A&R OSA metrics and targets agreed to with LIPA. See **Chapter XIII Performance Management** for further discussion.

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[64] DR 40

[65] http://www3.dps.ny.gov/W/PSCWeb.nsf/All/A4F227628F73D62F85257F57006320E3?OpenDocument

- The Board policy on Resource Planning, Energy Efficiency and Renewable Energy outlines LIPA's position for maintaining a power supply portfolio the meets applicable NYISO and NYS Reliability Council requirements, reliability studies and the State's Clean Energy Standard.[66]
  - These requirements were reflected in PSEG LI's development of the 2017 draft IRP:[67]

    > "This IRP examined the potential transmission and generation needs for long term system reliability under a range of scenarios and in the context of economic and policy considerations, including:
    >
    > – Meeting the newly enacted 50x30 Clean Energy Standard (CES), and
    >
    > – NYS Reliability Council and NYISO reliability planning criteria."

  - As discussed in **Chapter XIV-Fuel and Power Supply**, PSEG LI Power Markets organization also incorporates the Board's policy in its management of the power supply portfolio to minimize cost and maximize performance, including power plant availability and thermal efficiency, and in procuring cost effective renewable resources.

- Board Policies on Customer Service and T&D System Reliability link with PSEG LI's A&R OSA Tier 1 and Tier 2 performance targets. Examples are provided below.[68] The PSEG LI performance management process and LIPA's oversight is discussed in more detail in **Chapter XIII Performance Management**.
  - The Board Policy on Customer Service requires LIPA to achieve high levels of customer service and satisfaction, by achieving first quartile performance in industry standard customer service metrics by 2018.
  - The policy similarly requires customer satisfaction within the first quartile of peer utilities by 2022, as measured by third party (i.e., JD Power) and internally-generated customer satisfaction surveys.
  - The Board policy on T&D Reliability requires LIPA to achieve first quartile performance (as measured by the System Average Interruption Duration Index – excluding major storms) compared to peer utilities.

17. LIPA has increased its use of measurable goals and Key Performance Indicators (KPIs) to assess progress, and should continue this process.

- PSEG LI management focuses on the A&R OSA performance metrics (discussed in more detail in **Chapter XIII Performance Management**. These same metrics are reported to the LIPA Board as part of LIPA's annual performance reporting.

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[66] Resolution #1372, approved July 26, 2017 (www.lipower.org)

[67] 2017 Integrated Resource Plan: PSEG Long Island Analysis Summary, Draft April 10, 2017 (www.lipower .org)

[68] Resolution #1370

- LIPA has begun introducing more defined goals, metrics and key performance indicators to monitor LIPA’s progress toward achieving its internal performance goals.[69]

- LIPA’s goals are presented in its Operations and Oversight Plan, as shown in **Exhibit III-17**.[70] The Operations and Oversight Plan provides a three-year roadmap of activities to be undertaken to achieve the Authority’s strategic objectives. Supporting activities are assigned to the various LIPA Departments to facilitate execution. While some of the current goals are measurable with specific targets, others remain less defined.

Exhibit III-17
Alignment between LIPA and Departmental Goals

LIPA Initiatives/Goals	Target Date	Linked to a Department Goal				
		Ops Oversight	**Fin. Oversight**	**Finance**	**Legal**	**Executive**
Invest in the reliability of Long Island’s electric grid						
1. Complete the Integrated Resource Plan (IRP)	2017 2019 update	✓				
2. Complete the existing $730M storm hardening program for 2019 and assess plans for future investments	2019	✓	✓			
3. Develop Board policy for reliability at a system wide and circuit-by-circuit basis	2017	✓				
4. Develop Board policy on Wholesale Markets and Generation Planning	2017	✓				
5. Review multi-year investment plans for physical and cyber security	2018	✓				
Enhance customer service and value						
6. Establish new multi-year performance goals for reliability and customer service at the conclusion of the initial five-year targets in 2018	2018	✓				
7. Develop Board policy on customer service and value	2017	✓				
8. Advocate for fair transmission and gas costs to reduce power supply costs	2019	✓				
9. Reduce hidden burden of high taxes and fees by promoting property tax transparency and preparing an annual report on property tax reduction efforts and policy alternatives	2017-2019			✓	✓	
10. Complete refinancing plan to refinance 60 percent of LIPA’s debt						

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[69] Review of Board Policies (www.lipower.org) and DR 6 Supplement

[70] http://www.lipower.org/pdfs/company/papers/board/policies/2017_LIPA_Operations_Overisght_Plan.pdf, Appendix (DR 40)

LIPA Initiatives/Goals	Target Date	Linked to a Department Goal				
		Ops Oversight	Fin. Oversight	Finance	Legal	Executive
with Triple-A rated bonds to reduce cost for customers						
11. Complete and implement the findings of the 2018 DPS management audit	2017-2019					✓
Promote affordability						
12. Plan for and maintain regionally competitive rates in long term capital and financial plans	2017		✓			
13. Expand low income program benefits and participation to promote affordability	2017-2018					✓
14. Enable customer to lower electric bills through energy efficiency and other programs that reduce system cost						
Build a clean energy future						
15. Complete 400 MW renewable energy procurement to power 100,000 more homes with clean energy	2017	√				
16. Establish new goals/programs for energy efficiency to reduce peak loads and cost at conclusion of the efficiency Long Island program in 2018	2018	✓				
17. Develop a Board Policy on clean energy and distributed energy resources that meets statewide policy goals for 50% renewable energy by 2030 in a cost effective manner						
18. Advocate for public policy transmission projects to support off-shore wind and meet statewide goals	2019	✓				
Transition to a 21st century utility						
19. Develop advanced metering and electric vehicle programs that lead the way towards fulfilling emerging customer expectations	2017	✓				
20. Oversee PSEG LI's Utility 2.0 long-range plan, including its efforts to integrate distributed resources into T&D system planning and operation	2017 2019	✓				
21. Create a rate modernization roadmap to modernize electric rates	2017-2019	✓				✓
22. Incentivize system efficiency and provide more accurate pricing						
Exercise fiscal responsibility and maximizing the benefits of public ownership						
23. Continue to adopt and refine best practices in governance	2017-2019				✓	✓
24. Reduce cost for customers by increasing credit ratings and reducing debt						
25. Enhance enterprise risk management through comprehensive reviews of	2017-2019			✓		

LIPA Initiatives/Goals	Target Date	Linked to a Department Goal				
		Ops Oversight	Fin. Oversight	Finance	Legal	Executive
significant risks						
26. Pursue process improvements that institute best practices for budgeting and energy sales forecasting						
27. Review process compliance with FEMA storm hardening grant requirements	2017-2019		✓			
28. Support industry associations and advocate for the preservation of the benefit of tax-exempt debt in the event of federal tax reform	2017			✓		
29. Advocate continuation of federal incentives for renewable energy projects and improved access to federal credits by public power utilities	2019			✓		
30. Develop a Board Policy on economic development						✓

Source: NorthStar Analysis, Operations and Oversight Plan 2017-2019 (DR 40).

- Department goals are appropriately tied to the Authority's priorities and initiatives, as shown in **Exhibit III-17**. Departments may have additional goals associated with the performance of their function or oversight requirements, which are tied to LIPA's priorities. Department goals suffer from the same lack of specificity; they have themes and general requirements that do not support concrete deliverables or managerial accountabilities.

18. LIPA is in the process of executing its strategic plan.

- **Exhibit III-17** provided LIPA's strategic goals as outlined in its 2017-2019 Operations and Oversight Plan. As discussed in this and other Chapters, many of the 2017 goals have been achieved.
    - A number of Board policies were implemented, including Power Supply Hedging, Economic Development, and Enterprise Risk Management.
    - The draft IRP was released in 2017.
    - LIPA has reduced the cost of debt.
- Annual reports to the Board are used to demonstrate progress made during the preceding year in achievement of Board Policies. The Board Policies are more defined and specific than prior goal setting exercises. The 2017 Annual Board reports incorporated PSEG LI performance results where appropriate (e.g., Customer Service; Resource Planning, Energy Efficiency; and Renewable Energy; Transmission and Distribution System Reliability).[71] Under the new governance model, LIPA is moving toward the use of more KPIs for reporting performance

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[71] www.lipower.org Board Policies and associated Annual Report

against Board policies that are primarily driven by LIPA's activities such as Regionally Competitive Rates, Debt and Access to Credit Markets and Property Taxes.[72]

19. LIPA has established processes to monitor progress towards it long-term strategic goals on an ongoing, periodic basis. As the multi-year planning process is new for LIPA additional tools may need to be developed.

- LIPA interfaces with PSEG LI to monitor performance through the review of metrics, audits, and other information provided by PSEG LI.

- LIPA provides an annual report to the Board regarding its progress in implementing its policy objectives. Prior to 2017, these reports covered all objectives in one report. The reports focused more on activities and accomplishments, rather than quantitative performance measures. With the introduction of the revised governance model, LIPA updates the Board on its progress relative to each policy. The reports are more detailed and quantitative.

- LIPA and PSEG LI both attend the BOT meetings and provide the Board with performance updates.[73]

- NorthStar was able to observe selected meetings of PSEG LI and LIPA, and the LIPA Board and Committee meetings, but did not observe LIPA's internal meetings.

- LIPA and PSEG LI senior staff meet the first Tuesday of each month as the Management Review Board (MRB), to review performance data, discuss relevant issues as they pertain to utility operations, and maintenance of LIPA's T&D assets.[74]

- NorthStar attended two MRB meetings, generally held the same day as, and an hour before the Monthly Balanced Scorecard meetings. The MRB is attended by LIPA and PSEG LI senior management to provide updates on a wide variety of topics such as:

    - PSEG LI answers LIPA's questions and issues from previous meetings.
    - Current litigation highlights.
    - Real estate and facilities expansion alternatives.
    - Major program updates such as ERM, IRP and Utility 2.0.
    - New business.
    - Scorecard highlights preview of the Balanced Scorecard meeting.

- During the Monthly Balanced Scorecard meetings, LIPA and PSEG LI review performance against the A&R OSA Metrics. PSEG LI provides a performance update and addresses questions raised by LIPA. PSEG LI also provides additional

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[72] www.lipower.org, DR 6 Supplement and Attachments

[73] Direct observation, BOT meetings

[74] DR 293

information on key initiatives or activities. These meeting evidence a positive exchange between PSEG LI and LIPA.[75]

  - To increase the effectiveness of the meetings, LIPA provides PSEG LI with questions on the metrics in advance to facilitate discussion during the meeting.
  - Issues or questions raised during the meetings are addressed at subsequent meetings or through additional information provided to LIPA.

20. The LIPA employee performance evaluation process is generally aligned with LIPA's mission, objectives and goals. Performance is considered in promotions and salaries, but LIPA does not have an incentive compensation program.

- As part of the annual performance evaluation process, LIPA established individual employee goals and evaluation criteria that align with the functions served by LIPA staff and the Department goals as set forth in LIPA's Operations and Oversight plan.[76]

  - Performance evaluations are used for merit increases and to assist employees in improving performance.
  - LIPA has no short-term or long-term incentive programs.[77]

- LIPA department heads summarize the performance scores of their employees (on a scale of 1 to 5) and accomplishments for presentation to the Performance Evaluation Committee which consists of the CEO, CFO, GC and three VPs. The CEO evaluates the members of the Performance Evaluation Committee.[78]

  - Non-exempt employees are evaluated based on core competencies (e.g., job skills, quality of work, peer relationship management) and the completion of annual goals.[79]
  - Exempt employees are evaluated based on competencies that include leadership and service provider oversight and or LIPA management, and achievement of annual goals.[80]

- NorthStar also reviewed the 2017 performance evaluation goals for selected LIPA employees. As part of the performance evaluation process each goal has associated "measurements". The goals were generally specific, and were aligned with the individual's job function and LIPA's priorities. .[81]

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[75] Direct Observation, IR 133 and 215
[76] DR 8
[77] DR 8 and 9
[78] DR 8
[79] DR 10 Part 1
[80] DR 10 Part 2
[81] NorthStar Analysis, DR 1001 Attachment 1

- With the adoption of the Board Staffing and Employment Policy in 2017, LIPA is working to design a performance-driven compensation program linking individual performance, achievement of goals and competitive salaries.[82]

Transparency and the Public

21. LIPA has taken some positive steps to improve the transparency of its operations to key stakeholders. However, transparency could be further improved.

- LIPA Board meetings and some Committee meetings can be viewed on LIPA's website.[83]

- The Board does not have Policies that address how the objectives of transparency and public participation will be achieved.[84]

- LIPA's Operations Oversight Plan containing its Mission and Values can be expanded to address transparency.[85]

- Board and Committee materials are available on-line.

    - Board and Committee meeting agendas along with related documents are posted on LIPA's website prior to scheduled meetings.
    - Minutes for each meeting are posted on the website shortly after the meeting.
    - While agendas and minutes are left on the website for a year or more, supporting documents and full policy statements are available for a few months. Only the most recent Board meeting has documentation on the website associated with policy decisions.[86] All Board and Committee meeting materials are available via Freedom of Information Law (FOIL) request. According to LIPA, it receives virtually no such requests for historical Board and Committee materials from the public, outside of litigation-related requests.[87]

- Board and committee meetings may be viewed on-line in real-time.

- Consent Agenda items are listed in the agenda. The Board has stated that any item can be moved from the Consent Agenda to the full Board at the request of a Trustee.

- LIPA regularly has "pre-BOT briefings" the week prior to Board meetings. These briefings generally occur during the week prior to the Board meeting.

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[82] DR 8

[83] http://www.lipower.org/webcast/

[84] http://www.lipower.org/profile/mission.html

[85] http://www.lipower.org/pdfs/company/papers/board/policies/2017_LIPA_Operations_Overisght_Plan.pdf (DR 40)

[86] http://www.lipower.org/profile/trustees-documents.html

[87] LIPA/PSEG LI Fact Verification

- Briefings involve LIPA senior management and two to four Trustees.[88]
- The briefings are not public.
- While LIPA did not provide NorthStar access to these briefings, it is our understanding that items from the upcoming Agenda are discussed with the Trustees.

22. LIPA affords the public the opportunity to speak at BOT meetings.

- LIPA's Guidelines for Public Participation at Board meeting state that "New York State's Open Meetings Laws give the public the right to attend open sessions of public bodies but do not provide a right for the public to speak at such sessions."[89] Highlights include the following:
  - As time permits, individuals will be given an opportunity to speak on issues in accordance with the Agenda.
  - Any member of the public wishing to address the Board may sign the speaker sign in sheet at the designated table outside of the Board room before the beginning of the Board meeting and indicating the issue or matters on which they wish to speak.
  - The public comment periods are not intended to be "Question and Answer" periods or conversations between the public and the Board or Authority staff.
- Comments, whether on agenda items or on general matters, are limited to three minutes

D. RECOMMENDATIONS

1. LIPA Financial Oversight should formally document the results of its PSEG LI oversight activities and assessment process annually with submission to LIPA/PSEG LI executive management as well as DPS.

2. LIPA should formally request appointments or confirm extensions to Board member term periods at least six months prior to term expirations.

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[88] DR 864 Attachment 6

[89] http://www.lipower.org/pdfs/company/papers/board/policies/Guidelines%20for%20public%20participation%20at%20LIPA%20Board%20Meetings.FINAL.pdf

IV. ENTERPRISE RISK MANAGEMENT

A. BACKGROUND

Enterprise Risk Management (ERM) is the broad 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. Depending on the size, type and potential impact of the risks, 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.

For organizations that provide essential services, ERM typically 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 a Service Provider – which became Public Service Enterprise Group Long Island LLC (PSEG LI) as of January 1, 2014. There should be a strong ERM focus within LIPA, with a clear directive and close coordination between LIPA and PSEG LI to identify, define, and manage risks. Among other factors, there should be a clear statement of responsibility for risk management and accountability for any risk events. As in any organization, the risks — financial and operational — associated with decisions, and options for managing those risks should be a clear part of corporate decision-making.

In the 2013 LIPA Management and Operation Audit, NorthStar found that LIPA had no formal ERM process. NorthStar recommended that LIPA:

> 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.[1]

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[1] Matter No. 12-00314, "Comprehensive Management and Operations Audit of Long Island Power Authority Final Report" dated September 13, 2013 performed by NorthStar Consulting Group, Inc., p. X.

B. EVALUATIVE CRITERIA

- Does LIPA have a formalized process (e.g., ERM) for assessing the risks versus benefits of capital plans?
- Are variables used in the ERM models, and the weightings given to those variables appropriate and representative of LIPA's specific situations?
- Are suitable processes employed by LIPA and PSEG LI to assess and rank risks to the organization, including physical, financial and operations dimensions?
- Have LIPA and PSEG LI taken appropriate steps to address the areas identified as the highest risk?
- Is the schedule used by LIPA to update the ERM reasonable?
- Does LIPA include its key outside service providers, including PSEG LI, in its ERM process?
- Is the breadth and scope of the ERM process within LIPA consistent with good practices?
- Are the results of the ERM incorporated into strategic plans and other corporate decision-making at the executive and Board level?
- Are the potential financial impacts of key risk factors and major decisions adequately incorporated into the ERM processes and reports?

C. FINDINGS AND CONCLUSIONS

1. In response to NorthStar's 2013 LIPA Management and Operations Audit recommendation 7.4.1, LIPA took steps to develop an ERM process, and has a formal risk management process that is being implemented across LIPA and PSEG LI. LIPA acknowledges that its efforts from 2014 through 2016 may be summarized as "a period of learning, trial and error."[2]

- In 2014, PSEG LI, Public Service Enterprise Group (PSEG) and LIPA staff met to coordinate implementation of a formal comprehensive ERM process.[3]

  - The initial intent was to apply PSE&G's ERM process and tools, but LIPA determined that PSEG's ERM program was not sufficiently mature for its immediate purposes.[4]
  - LIPA then retained an outside consultant to assist in the development of an ERM program.[5]

- In early 2015, LIPA and the outside consultant conducted LIPA's first formal enterprise risk assessment. This effort produced separate risk matrices for LIPA and PSEG LI in June 2015.[6]

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[2] DR 425

[3] DR 240 Response 4

[4] DR 240 Response 4

[5] DR 961

[6] DR 240 Response 4, DR 240 Attachment 2 and 3

- On August 7, 2015, the LIPA Board of Trustees (BOT) approved LIPA's first Governing Policy for ERM, outlining the objectives, framework, and delegation of authority for the ERM Program.[7]

  - The governing policy placed ERM under the direction of the Executive Risk Management Committee (ERMC).
  - As explained in the Board Policy, ERMC members include the Chief Financial Officer (as the ERMC Chair) and at least two other LIPA members, one of which must be from LIPA's senior management.[8]

- LIPA continued to refine the ERM program in 2016. In Spring 2016, LIPA used a top-down approach to identify risks. An ERM team composed of LIPA staff (with assistance from the outside consultant), interviewed 47 senior managers from LIPA and PSEG LI, and PSEG's Chief Risk Officer.[9] Summary results were published to a group of senior managers at LIPA and PSEG LI, who then completed an anonymous on-line survey to prioritize risk items.[10]

- The results of the 2016 ERM cycle led to a list of findings and potential areas for mitigation. The 2016 ERM effort did not reveal any unattended risks or other risks that were not already the focus of mitigation efforts by LIPA and/or PSEG LI. The cycle and development of formal mitigation plans did provide a means to identify risk owners who were responsible for mitigation action plans. According to LIPA, many of the mitigation plans developed as a result of the 2016 effort have been deployed or are on-going.[11]

- At the end of 2016, LIPA recognized that it should have an ERM program, but realized that in light of the unique LIPA/PSEG LI organization structure, it should use a different approach to develop the program, including the establishment of a collaborative ERM Steering Committee comprised of ERM staff from LIPA, PSEG and PSEG LI who would develop and implement the ERM Program.[12] As described by LIPA:

  > "The ERM work performed in 2016 led to a decision to seek new approaches to ERM. While the efforts over the past three years may be summarized as a period of learning, trial and error, ERM is now a permanent component of the LIPA/PSEG Long Island management environment that it will continue to grow and mature in the future."[13]

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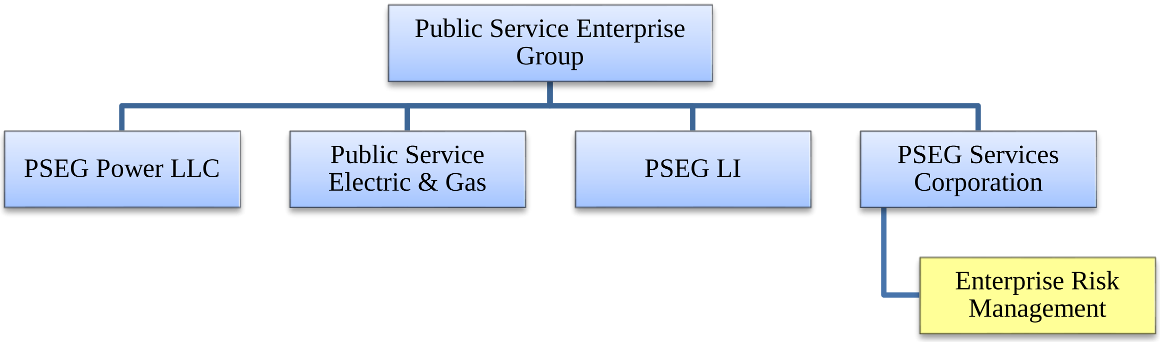
[7] DR 50 Attachment 1
[8] DR 50 Attachment 2
[9] DR 961
[10] DR 240 and DR 425 Attachment 2
[11] DR 425
[12] DR 953 Attachment 1
[13] DR 425

2. PSEG has an Enterprise Risk Management Group that works with lines of business throughout the enterprise.

- PSEG has an Enterprise Risk Management Group that works with lines of business throughout the enterprise. The ERM Group is part of the PSEG Services Corporation (PSEG Services) as shown in **Exhibit IV-1**.

Exhibit IV-1
PSEG Services Enterprise Risk Management Group



Source: DR 583.

- The Vice President (VP) of PSEG Services ERM serves as PSEG's Chief Risk Officer and reports to the PSEG's Chief Financial Officer (CFO).

- PSEG Services ERM does not have a dedicated group to support PSEG LI. A staff of two work with all lines of business across PSEG to ensure there is a consistent approach to risk throughout the corporation.[14]

- PSEG Services ERM conducts an annual identification and assessment for PSEG. PSEG LI's Vice President – Business Services serves as risk liaison for PSEG LI and helps to score risks relevant to PSEG LI.[15]

- As discussed in Conclusion 6, PSEG Services ERM is currently working with LIPA to implement a joint LIPA – PSEG LI ERM program.

- As discussed in Chapter XIV, PSEG Services ERM also provides Middle Office services related to LIPA's Power Supply Management and Fuel Management agreements.

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[14] IR 109
[15] DR 961

3. **After its approaches to develop an enterprise-wide ERM in 2015 and 2016 met with limited success, LIPA appropriately took steps to learn about other utility approaches to risk management.**

   - In late 2016 and early 2017, LIPA met with other regional electric utilities to discuss their ERM program structures. LIPA:

     - Participated in several local ERM roundtable meetings.
     - Attended the annual Large Public Power Council (LPPC) ERM Roundtable meeting.[16]

   - LIPA determined that in many utilities, and within LIPA and PSEG LI, department staff is better suited than senior management to identify risks in their operations, and that the enterprise risk assessment process needed to be driven from the bottom-up.[17]

4. **In 2017, LIPA embarked on a new bottom-up approach to risk identification. LIPA's approach to ERM is still evolving, and it has the elements in place to make it successful. The current ERM approach includes processes to identify and rank risks across all departments. LIPA intends to include ERM results in its strategic plans and other executive decisions, but it is too early in the program's development to perform a detailed assessment of the effectiveness of the program.**

   - In February 2017, the ERMC adopted a new ERM Procedure Manual that thoroughly revised the process based on LIPA's first two years of experience.[18]

   - The current 2017 ERM Program seeks to provide a systematic and consistent approach to risk management. The ERM Program is executed using a bottom-up (department-level) approach to identify risks and mitigation plans for LIPA and PSEG LI, with guidance from LIPA's ERM, the ERMC and the LIPA/PSEG LI Senior Leadership Team (See Conclusion 5).

     - The new ERM Program focuses on empowering the operating departments to manage their risks by providing them with the tools and capabilities to identify, assess and prioritize, develop response plans and to monitor and report risk trends up to senior management.
     - The ERM Program strives to help management achieve and/or develop strategic initiatives and effective business strategies, while the balance of the organization focuses on development and monitoring the effectiveness of mitigation strategies.
     - This approach enables management to consider the highest ranked risks across the organization when prioritizing capital allocations to reduce the likelihood and

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[16] DR 55 Attachment

[17] DR 50

[18] DR 50

severity of risks which may affect the achievement of the utility's mission, goals and key priorities.[19]

- In February 2017, LIPA hired a new outside consultant as its new ERM advisor.[20] The consultant's overall scope is to "provide LIPA with advice and recommendations on its journey to enhance its existing enterprise risk assessment and overall risk management practices."[21]

- LIPA's 2017 ERM activities focused on the assessment of LIPA's departments through a workshop process.[22]

  - The LIPA ERM team, supported by the outside consultant, facilitated the workshops with the LIPA departments in 2017.
  - LIPA departmental assessments were still on-going in late 2017.[23]
  - LIPA expects that the process for PSEG LI risk assessments/workshops will start in first quarter of 2018.[24]
  - LIPA plans to use lessons-learned from its 2017 workshops in its future workshops.

- **Exhibit IV-2** presents an overview of the workshop steps.

Exhibit IV-2
Departmental ERM Workshop Steps

Step		Description
1	Overview	• Provide an overview of the ERM Program, its value and the importance of aligning risks to LIPA's mission, vision, values, and key strategic priorities. • Engage dialogue on the operating department's objectives and begin to identify risks at the business unit level.
2	Risk Identification and Assessment	• Develop department risks, risk definitions, specific risk drivers and consequences, assessment and prioritization activities. • Identify risk response and document mitigation strategies with risk owners.
3	Risk Prioritization Ranking / Assessment Review	• Review department risk dashboards and prioritization scores, drivers for each risk and overall ranking of all department risks to determine if the hierarchy is reasonable. • Consider which risks require deeper review through bow-tie analysis.
4	Bow-Tie Analysis (if necessary)	• Review selected department business risks that required a deeper-dive into a risk driver's causes and consequences (externally-imposed risks, strategic risks, and self-inflicted risks) and trigger events.

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[19] DR 954 Attachment 1
[20] DR 344 Attachment 2
[21] DR 344 Attachment 2
[22] DR 953 Attachment 1
[23] DR 961 Attachment 1
[24] DR 961

Step		Description
5	Key Risk Indicators (KRIs) (if necessary)	• Focus on selected high-priority risks to develop KRIs from bow-tie analysis. • Discuss development of KRI parameters and data sources, availability and frequency of the data and relevant monitoring thresholds (e.g., green, yellow, red.)
6	Department Risk Portfolio Review	• Review overall department risk portfolio, including risk mitigation plans/activities, management reporting, and department risk owner sign off.
7	Risk Portfolio Reporting	• ERM staff assist department risk owners in populating Risk Management Reports for various levels of LIPA and PSEG LI senior management (e.g. ERMC, Senior Leadership Team and LIPA BOT Finance & Audit Committee.)

Source: DR 953 Attachment 1.

- In early 2018, LIPA is completed staffing an internal ERM organization.
  - In fall 2017, LIPA hired the recently retired Director of Enterprise Risk Management from Consolidated Edison Company of New York, Inc. to serve as a part-time ERM Advisor (separate from the outside consultant).[25] The role of the ERM Advisor is to use his previous experience and expertise as an ERM practitioner to assist the LIPA ERM team with the continued development and enhancement of its ERM program, including risk analytic tools, and facilitating various workshops throughout the ERM process.[26]
  - LIPA hired a Utility Enterprise Risk Manager in January 2018 whose responsibilities include: planning, scheduling and executing the ERM Program components across all utility departments; preparing materials and facilitating risk workshops; and managing milestones and key deliverables required by each department to meet the ERM project timeline.[27]

- LIPA expects its ERM procedures to continue to evolve to incorporate feedback gained from the participation of LIPA and PSEG LI's staff in the risk identification, prioritization and documenting of mitigation activities.[28] The ERM Advisor's responsibilities includes tasks specifically focused on enhancing the ERM program, including:
  - Proactively identify Enterprise Risk Assessment process improvements which are consistent with utility best practices.
  - Attend and participate in regional ERM roundtable meetings to identify leading ERM practices and processes for implementation at LIPA.
  - Provided recommendations for revisions to LIPA's internal ERM Procedures Manual for consideration by LIPA's ERMC.
  - Develop criteria for determining when a deeper evaluation of risk should be performed and criteria for what risks should be elevated to senior management.

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[25] DR 953 Attachment 1
[26] DR 954 Attachment 1
[27] 2/1/2018 email from LIPA
[28] DR 50

- Develop criteria for monitoring emerging risks and communication mechanisms to report key emerging risks to management.
- Work with LIPA's Director of Internal Audit and Director of Risk Management to administer internal operational risk management improvement processes.[29]

5. **The governance structure for LIPA's current ERM approach is appropriate. The LIPA Board and LIPA and PSEG LI senior management will be responsible for oversight of the ERM program once the new program is fully implemented.**

- **Exhibit IV-3** shows the governance structure for the 2017 ERM approach.

Exhibit IV-3
ERM Governance Structure

Source: DR 50 Attachment 2.

- **Board of Trustees** – The BOT sets the ERM Governing Policy and must approve any changes. The Finance and Audit Committee of the Authority's Board is responsible for oversight of the ERM Program.[30]

- **Senior Leadership Team** – Composed of all LIPA and PSEG LI staff in the capacity of Vice President and above, plus any other members of the ERMC and PSEG's Chief Risk Officer. As the Senior Leadership Team includes the senior management of both LIPA and PSEG LI, it is in the best position to make judgements about the

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[29] DR 954 Attachment 1

[30] DR 50 Attachment 1

adequacy of the ERM program and to ensure that the ERM activities are used in the day-to-day management of the enterprise.[31]

  - The Senior Leadership Team will meet on a quarterly basis beginning in early 2018.
  - The Senior Leadership Team will review both LIPA's and PSEG LI's Corporate Risks and other ranked risks and the mitigation and monitoring activities on a department-by-department basis.
  - Each quarter, the Senior Leadership Team will perform a detailed review of one LIPA or PSEG LI department. The Senior Leadership Team will meet with the most senior member of the selected department to review that department's risks in detail.[32]

- ERMC – LIPA's Board authorized the ERMC to coordinate the procedures and oversight of LIPA's ERM activities. The ERMC has the authority to delegate certain tasks, activities, or functions to LIPA or PSEG LI staff or outside consultants, whereby all such tasks, activities or functions will remain under the control of the ERMC as part of the ERM program.[33]

  - The ERMC is chaired by LIPA's CFO, who is charged with Chief Risk Officer responsibilities. Other LIPA senior management personnel serve on the ERMC, including the CEO, Vice President of Financial Oversight, the Director of Risk Management and members of the Operations Oversight and Finance teams.[34]
  - A quorum of the ERMC, consisting of at least a simple majority of the voting members of the ERMC, meets periodically, generally monthly, to review implementation of the ERM program, risks, and monitoring efforts on a department-by-department basis.[35]
  - In addition, the ERMC shall specify those risks that meet certain criteria, as evaluated by each Department, as "Corporate Risks."[36]
  - A simple majority of the voting members present at any meeting will be sufficient to approve any action by the ERMC.[37]

6. LIPA appropriately includes PSEG LI in its ERM processes and the current ERM development effort.

- As discussed in Conclusion 1, LIPA first implemented an integrated LIPA/PSEG LI enterprise risk assessment process in 2016.

- As explained in the February 2017 ERM Procedure Manual, LIPA's key services (e.g., electric generation, transmission & distribution system management, reliability

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[31] DR 50 Attachment 2
[32] DR 50 Attachment 2
[33] DR 50 Attachment 2
[34] DR 141
[35] DR 50 Attachment 2
[36] DR 50 Attachment 2
[37] DR 50 Attachment 2

management, customer services, and communications) are outsourced to PSEG LI. For this reason, LIPA has designed its ERM program to include the participation of PSEG LI.[38]

- In fall 2017, PSEG Services ERM and LIPA ERM worked together to set up a Steering Committee and working group to further define the joint ERM effort between LIPA and PSEG LI.
  - PSEG Services ERM is currently conducting information sessions and ERM planning sessions with LIPA ERM to determine a path forward to execute the ERM Process for PSEG LI in conjunction with LIPA.
  - The plan is to create ERM foundations that reflect the interests of both entities and then execute the identification, assessment, mitigation and reporting process.[39]
  - The plan is to involve PSEG Services ERM, the PSEG LI ERM Liaison and LIPA ERM in the workshops to determine and prioritize the top risks for PSEG LI. While all parties are working on the joint ERM overall project plan in 2017, it is not expected that the process for PSEG LI risk assessments/workshops will start until first quarter of 2018.[40]
- PSEG LI hired a full time ERM resource to support PSEG LI on June 1, 2018.[41]

D. RECOMMENDATIONS

1. LIPA and PSEG LI should continue to develop an effective, comprehensive ERM process.

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[38] DR 50 Attachment 2

[39] DR 961

[40] DR 961

[41] 2017 Audit Factual Accuracy Review Items

V. BUDGETING AND FINANCIAL REPORTING

This chapter focuses on LIPA's and PSEG LI's development and reporting of the Operating and Capital budgets.

A. BACKGROUND

In accordance with the Amended & Restated Operations Service Agreement (A&R OSA), LIPA has oversight responsibility for the consolidated operating and capital budgets while PSEG LI is responsible for the development of budgets related to its obligation of managing the day-to-day operations and capital improvements of the Transmission and Distribution (T&D) system, and for preparing the Consolidated LIPA budget.[1] **Exhibit V-1** provides an overview of LIPA's and PSEG LI's budget responsibilities.

Exhibit V-1
LIPA and PSEG LI Budget Responsibilities

PSEG LI	LIPA
▪ Budget consolidation ▪ True-ups and staged updates ▪ Revenue requirements ▪ Sales and revenue forecasts ▪ Fuel and purchased power forecasts ▪ PSEG LI operating costs, incl. Generally Accepted Accounting Principles (GAAP) and cash pensions and other post-employment benefits (OPEBs) expenses ▪ PSEG LI managed expenses - National Grid PSA - Nine Mile Point 2 O&M - Uncollectible accounts - Storm restoration - NYS assessment - Accretion of asset retirement obligation - Miscellaneous operating expenses ▪ PSEG LI capital budget (incl. Allowance for Funds Used During Construction (AFUDC)) ▪ PSEG LI capital budget details ▪ Nine Mile Point 2 capital budget ▪ PSEG LI managed utility depreciation; amortization of prior deferrals (regulatory assets) ▪ Taxes, payments-in-lieu of taxes (PILOTs) and assessments ▪ Tariff leaves	▪ A&R OSA management fee, incl. capitalized portion ▪ LIPA operating expenses - Employee salaries and benefits - Insurance - Office rent - Other (misc.) G&A operating expenses - Professional services - Deferred expense amortizations ▪ Deferred transition costs ▪ Deferred pension and OPEBs expenses ▪ Deferred rate case expenses (if any) ▪ National Grid pension/OPEBs settlement ▪ LIPA depreciation and amortization of the acquisition adjustment ▪ PSA property tax settlement ▪ Other income and deductions ▪ Grant income ▪ Interest expense, incl. non-cash amortizations and other interest expense items ▪ Debt service and debt service coverage requirements ▪ LIPA capital

Source: DR 169.

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[1] DR 174 Attachment 1

In general, LIPA's capital and operating & maintenance (O&M) budgets include financing costs and the general and administrative (G&A) costs associated with its oversight responsibilities, while PSEG LI's capital and O&M budgets include revenue forecasts, fuel and purchased power costs, and costs associated with operating and maintaining the LIPA-owned T&D system.

The Consolidated LIPA budget is broken into several categories:

- Revenue Requirements
- Statement of Revenues and Expenses
- Sales and Revenues
- Power Supply Charge
- Operating and Deferred Expenses
- Depreciation, Amortization and Deferred Expenses
- Taxes, PILOTs and Assessments
- Other Income and Deductions
- Grant Income
- Interest Expense
- Debt Service Requirements
- Capital and Deferred Expenditures

LIPA and PSEG LI have a collaborative process to develop the consolidated LIPA budget. The Authority and its Service Provider develop their portions of the consolidated operating and capital budgets separately based on established formal schedules. These schedules support the rate case schedule for revenue and expense level resets (Delivery Service Adjustments (DSAs) and Staged Updates, described below) and the public release of budget information in November, and allow time for Trustee review and public comment before adoption of the budget at the December Board meeting.

Exhibit V-2 presents a high-level schedule of the consolidated budget process. LIPA's Vice President (VP) of Financial Oversight coordinates the timely completion and consolidation of the LIPA and PSEG LI budget submissions.[2]

Impact of the Three-Year Rate Plan on Budget Development

LIPA is a municipal instrumentality of the State of New York that is authorized by statute to establish its own rates and charges sufficient to meet its fiduciary responsibilities. LIPA is not subject to rate regulation by the New York State (NYS) Public Service Commission (PSC) nor the Federal Energy Regulatory Commission (FERC). The LIPA rate setting process is defined by the LIPA Act, as revised by the LIPA Reform Act.[3]

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[2] DR 170

[3] DR 145

Exhibit V-2
High Level Budget Preparation Milestones

Activity	Entity	Month
Budget kickoff with Senior Management	PSEG LI	April - May
Budget kickoff with Directors, Managers, Budget Liaisons, Budget Analysts	PSEG LI	April - May
Budget kickoff with LIPA and PSEG LI	Both	May - June
Chief Executive Officer (CEO)/Chief Financial Officer (CFO) Budget Message to LIPA department heads	LIPA	June
Distribution of instructions and templates to LIPA personnel	LIPA	July
PSEG LI internal review of initial budget	PSEG LI	August
LIPA internal review of departmental budget proposals	LIPA	August
LIPA submits budget to PSEG LI	LIPA	September
PSEG LI submits operating, capital and storm budgets to LIPA	PSEG LI	September
PSEG LI submits consolidated proposed budget to LIPA	PSEG LI	October
LIPA and PSEG LI review consolidated budget	Both	October
Proposed budget and multi-year plan presented to public	Both	November
Public input sessions	Both	November
Board of Trustees review and approval	Both	Mid-December

Source: DR 174 Attachment 1, DR 171 Attachment 1.

The LIPA Reform Act requires DPS to establish an evidentiary process for the initial Three-Year Rate Plan (2016 – 2018) and any subsequent proposal that would increase base rates by more than 2.5 percent of aggregate revenues.[4] LIPA and PSEG LI budgets for 2016 through 2018 implement the Three-Year Rate Plan that was approved by LIPA's Board in December 2015.[5]

Annual targets for O&M and capital for 2016 through 2018 are aligned to the Rate Plan results. As discussed in **Chapter VI – Debt Management**, in accordance with the Department Rate Recommendation, each fall the rates for the next year are trued up to reconcile actual and projected costs for selected categories of costs, notably storms and debt service-related costs, through the Delivery Service Adjustment (DSAs), and adjustments for known budget changes through the "Staged Update" process. The annual Staged Updates covers items that are subject to wide variability due to external factors, including costs resulting from changes in property taxes, the collective bargaining agreements and debt service costs, net of interest earnings. The Staged Updates are subject to DPS review and recommendation to the LIPA Board, and are presented to the LIPA Board with the annual budget.[6] The Board may also approve additional budget items.

Exhibit V-3 presents the rate case and Board-approved operating budgets for 2016 and 2017.

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[4] LIPA Reform Act

[5] DR 169

[6] DR 14 Attachment 163

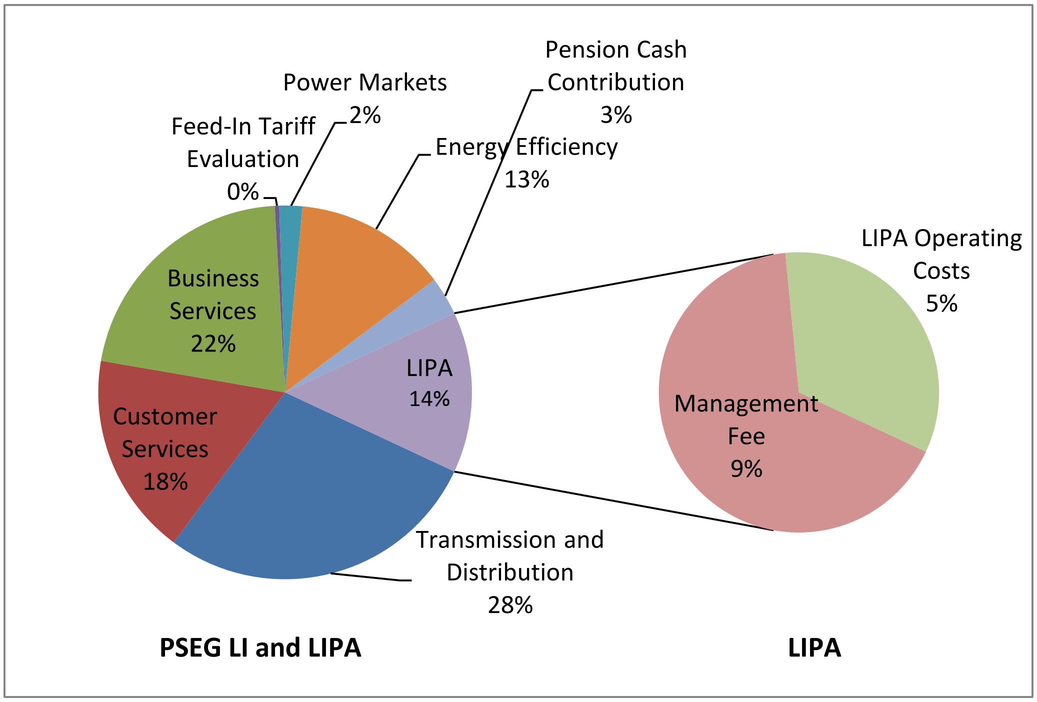
Exhibit V-3
Rate Case and Board Approved Operating Budgets for 2016 and 2017
(Dollars in Thousands)

	Rate Plan	Board Approved	Variance	Rate Plan	Staged Update	Adjusted Rate Plan	Board Approved	Variance
	2016			2017				
PSEG LI								
T&D	$170,943	$170,943	-	$173,628		$173,628	$189,797	$16,169
Customer Services	121,156	121,156	-	123,458		123,458	117,997	(5,461)
Business Services	137,912	137,912	-	151,228		151,228	144,025	(7,203)
Power Markets	13,328	13,328	-	13,152		13,152	13,409	257
Energy Efficiency	86,807	86,807	-	88,054		88,054	88,918	864
Turnover Adjustment	(1,634)	(1,634)	-	(1,674)	1,147	(527)		527
GAAP Pension and OPEBs Costs	(73,303)	(73,303)	-	(73,070)		(73,070)	(67,798)	5,272
Pension Cash Contribution	17,199	17,199	-	16,695	1,512	18,207	22,400	4,193
Emergency Troubleshooter	8,353		(8,353)	8,538		8,538		(8,538)
Feed-In Tariff Evaluation						-	2,598	2,598
PSEG LI Operating Expenses	**$480,761**	**$472,408**	**$(8,353)**	**$500,009**	**$2,659**	**$502,668**	**$511,346**	**$8,678**
LIPA								
Management Fee (including incentive)	$73,383	$73,383	-	$75,034		$75,034	$75,034	-
Capitalized Management Fee	(16,406)	(16,406)	-	(16,776)		(16,776)	(12,779)	3,997
LIPA Operating Costs	26,825	26,825	-	26,967		26,967	31,375	4,408
LIPA Operating Expenses	**$83,802**	**$83,802**	**-**	**$85,225**		**$85,225**	**$93,630**	**$8,405**
Consolidated			-					-
Consolidated Operating Expenses	**$564,563**	**$556,210**	**$(8,353)**	**$585,234**	**$2,659**	**$587,893**	**$604,976**	**$17,083**

Source: DR 782 Attachment 1.

As shown in **Exhibit V-4**, in 2017 LIPA's operating expenses were approximately 14 percent of the total operating budget of $672.8 million (this amount excludes the $67.8 million credit for GAAP pension and OPEBS costs). LIPA's stand-alone operating budget for 2017 was $93.6 million; about two thirds of this amount is the PSEG LI management fee ($62.3 million).

Exhibit V-4
Breakdown of the Consolidated LIPA 2017 Operating Budget



Source: DR 782

Exhibit V-5 shows the rate case and Board of Trustees (BOT) approved capital budgets for 2016 to 2018.

Exhibit V-5
Rate Case and Board Approved Capital Budgets for 2016 to 2018
(Dollars in Thousands)

	2016	2017			2018		
	Rate Plan [Note 1]	Rate Plan	Approved	Difference [Note 2]	Rate Plan	Approved	Difference [Note 3]
PSEG LI							
T&D	$366,760	$342,423	$398,771	$56,348	$369,834	$423,212	$53,378
Customer Service	$25,694	$26,146	$11,197	($14,949)	$26,557	$11,394	($15,163)
Information Technology (IT)	$22,559	$22,686	$38,180	$15,494	$22,183	$36,728	$14,545
Facilities	$4,841	$5,006	$5,006	$0	$5,162	$9,196	$4,034
2015 Deferred Capital Projects	$52,074	$0		$0	$0		$0
Fleet			$27,899	$27,899		$8,526	$8,526
DPS Recommended Capital Reductions	($14,170)	($15,700)		$15,700	($15,900)		$15,900
Utility 2.0						15,475	$15,475
PSEG LI Total (Excl. FEMA)	**$457,758**	**$380,561**	**$481,053**	**$100,492**	**$407,836**	**$504,531**	**$96,695**
LIPA							
LIPA Capital Expenditures & Deferrals	$15,794	$29,045	$27,922	($1,123)	$10,663	**$23,405**	$12,742
Capitalized Management Fee	$16,406	$16,776	$12,779	($3,997)	$17,153	**$30,632**	$13,479
AFUDC	$8,897	$7,198	$5,991	($1,207)	$8,108	**$7,874**	($234)
LIPA Total	**$41,097**	**$53,019**	**$46,692**	**($6,327)**	**$35,924**	**$61,911**	**$25,987**
Total Excluding FEMA	**$498,855**	**$433,580**	**$527,745**	$94,165	**$443,760**	**$566,442**	**$126,803**
Federal Emergency Management Agency (FEMA)	$186,200	$312,400	$188,754	($123,646)	$186,300	$190,273	$3,973
Total Capital Expenditures and Deferrals	**$685,055**	**$745,979**	**$716,499**	**($29,480)**	**$630,061**	**$756,715**	**$130,775**

Note 1: The 2016 Rate Plan and Approved Budget amounts were the same. The Rate Plan budget was adopted by the Board in December 2015.

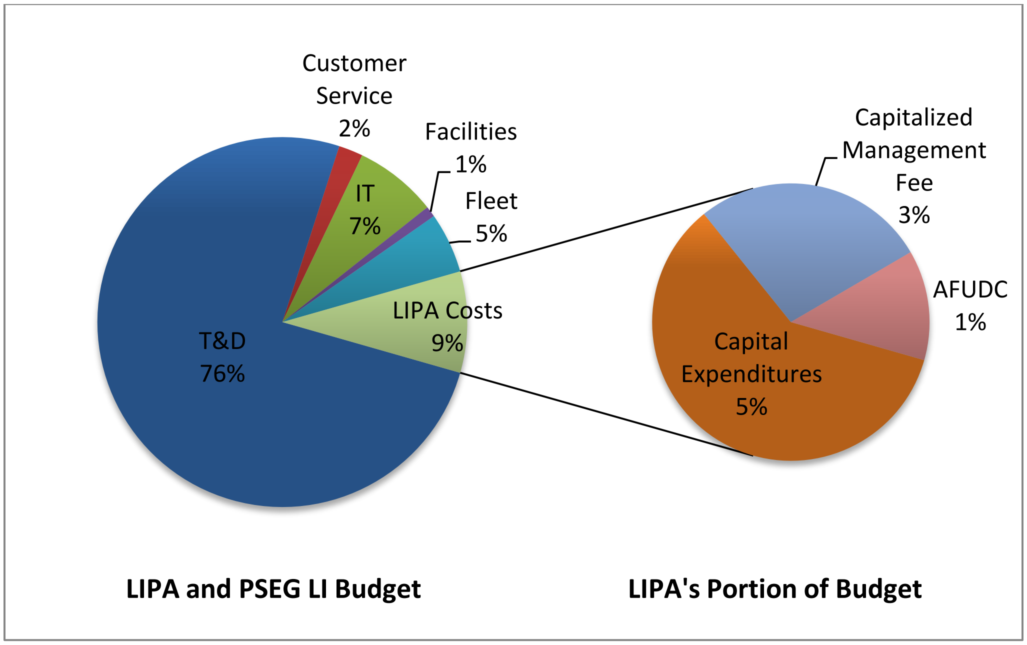
Note 2: PSEG LI increases from the rate plan due to project carry-over ($-4,000k), fleet ($27,899k), and changes in assessment ($7,275), union rate increase ($365k), and additional budget requests ($20,355k).

Note 3: PSEG LI increases from the rate plan due to project carry-over ($4,000k), fleet ($8,526k), and changes in assessment ($9,185k), union rate increase ($2,120k), and additional budget requests ($57,389k).

Source: DR 781 Attachment 1 and LIPA 2018 Budget http://www.lipower.org/pdfs/company/papers/LIPA_2018Budget%201-18%20web%20approved.pdf

PSEG LI is responsible for approximately 90 percent of the capital budget as shown in **Exhibit V-6**. This exhibit excludes the $188.8 million of FEMA-funded capital expenditures planned for 2017. In February 2014, the Authority signed a Letter of Undertaking with FEMA that provides for $730 million of grant funding for storm hardening measures.

Exhibit V-6
Breakdown of the Consolidated LIPA 2017 Capital Budget (Excludes FEMA)



Source: DR 781 Attachment 1.

Financial Reporting

LIPA’s Controller is responsible for the monthly consolidation of LIPA, Utility Debt Securitization Authority (UDSA), and PSEG LI financial statements and the following monthly management reports to the Board’s Finance and Audit Committee and/or LIPA and PSEG LI management.

- Year-to-Date Statement of Revenue and Expenses and changes in Net Position
- Statement of Net Position
- Capital Spending vs. Budget, and a detailed review of capital projects greater than $25 million.
- Statements of Cash Flows (for management review).[7]

The Controller also produces Quarterly Financial Statements that must be issued within 45 days from the end of the quarter and provided to banking syndicates and LIPA’s disclosure counsel for posting to the Electronic Municipal Market Access (EMMA) website. LIPA also produces Annual Audited Financial Statements that must be issued within 90 days

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[7] DR 271 Attachment 2, pp. 34-35 and LIPA/PSEG LI Fact Verification

from the end of the year.[8] The quarterly and annual financial statements are available on LIPA's website.

B. EVALUATIVE CRITERIA

Budgeting

- 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?
- Is the construction/capital priority setting process balanced, consistent and appropriately executed from the top down? (See **Chapter IX - Program and Project Planning and Management**)
- Are incremental O&M expenses associated with new construction factored into the budgeting process in an appropriate manner?
- Do allowed revenues/rates and financing opportunities or constraints adversely affect budget levels and priorities?
- Are relationships among planned/budgeted expenditures and actual expenditures appropriate? (See **Chapter IX - Program and Project Planning and Management**)
- Is the capital budgeting process documented, adhered to, appropriate and effective?

    - Project authorization
    - Project appropriation
    - Increases/decreases to authorization and appropriation amounts
    - Capital budget status reporting
    - Validation in advance of appropriation
    - Funding controls and other elements of the process (See **Chapter IX - Program and Project Planning and Management**)

- Do LIPA and PSEG LI use budgeting guidelines, practices and procedures, including "zero-based" and other alternative methods, effectively?
- Do LIPA and PSEG LI have an effective methodology for prioritizing and approving capital projects? Also see **Chapter IX - Program and Project Planning and Management**.
- Does capital project estimating produce accurate results that are sufficiently detailed to yield accurate cost estimates? (See **Chapter IX - Program and Project Planning and Management**)
- Do LIPA and PSEG LI use appropriate modeling software in the capital and O&M budgeting processes?
- Are LIPA and PSEG LI appropriately involved in the capital project prioritization process?

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[8] DR 271 Attachment 2

- Are capital budgets managed and controlled? See also **Chapter IX - Program and Project Planning and Management**.
- Are bottom-up and top-down processes for developing budgets for capital/construction classifications and categories appropriate?
- Are the reports provided to managers clearly related to the budget and provide data that are helpful to managers in achieving budget goals? See also **Chapter IX - Program and Project Planning and Management**.

Budget Control

Findings and conclusions related to these criteria, as well as the same criteria, are contained in **Chapter IX – Program and Project Planning and Management**.

- Do capital and O&M plans and budgets convert to specific programs and projects in an effective manner?
- Do LIPA and PSEG LI have an effective methodology for tracking costs, work units and work quality for specific programs and projects?
- Do LIPA and PSEG LI routinely identify typical variances between original budgeted and actual capital expenditures and work units?
- Do LIPA and PSEG LI track and minimize variances in order to improve the cost control, efficiency/productivity and work quality?

Financial Reporting

- Is the flow of information into the general ledger and the quality and consistency of source data sufficient for oversight of PSEG LI?
- Do manual reporting processes provide meaningful and timely management information and are they channeled in a way that supports an information hierarchy?
- Is the data reported by systems for significant adjustments or corrections reliable and accurate?
- Does the chart of accounts structure capture data effectively and efficiently?
- Are the internal controls around financial systems and audit trails sound and are they periodically reviewed?

C. FINDINGS AND CONCLUSIONS

Budgeting

1. **LIPA has adequate budgeting guidelines, practices and procedures for a company of its size. Due to limitations in its financial system, LIPA's budget development process is largely Excel-based.**

- LIPA issued a budgeting procedure in December 2015, and updated this procedure in November 2016 and October 2017. This document provides guidelines for the annual budgeting process and budget monitoring process, which are collaborative efforts between LIPA and PSEG LI.[9]

- LIPA's Financial Oversight Department is responsible for planning and administering LIPA's budget process.[10] Its key budget-related activities include:
    - Developing a budgeting template in Excel.
    - Preparing an instructional and policy package for the cost centers.[11]
    - Meetings with department heads and the individuals responsible for budget preparation early in the budget cycle to discuss new funding requests, alignment between LIPA's objectives and spending, any rate plan spending caps.[12]
    - Compiling the completed budget template data and preparing summary budget presentations and analytical reports to assist in the evaluation of the proposed spending plans.[13]

- For budgeting purposes, LIPA is divided into departments/cost centers as follows:
    - Corporate
    - Operating
        - Finance
        - Financial Oversight
        - Human Resources
        - Internal Audit
        - Office of the General Counsel and Secretary
        - Operations Oversight
        - Office of the Chief Executive Officer
        - Administration.[14]

- Each departments/cost center develops its portion of the capital and O&M budgets using an Excel template.
    - Budget templates are pre-populated with the current year's approved budget and next year's Rate Plan budget restated for organization changes and approved salary adjustments. Each Department's Budget Template reflects line items specific to that department based on historical spending.[15]
    - The budget templates also include a tab for identifying potential risks for budgeted results and opportunities for improving on the results. From these Risks

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[9] DR 174 Attachment 1and LIPA/PSEG LI Fact Verification

[10] DR 174 Attachment 2

[11] DR 174 Attachment 1

[12] DR 174 Attachment 1

[13] DR 174 Attachment 2

[14] DR 174 Attachment 2

[15] DR 174 Attachment 5

    and Opportunities, further resource reallocation may be made at the corporate level.[16]
  - Budgets are prepared in monthly detail for the immediate budget year and at an annual level for the subsequent budget year(s).[17] LIPA's budgeting cycle encompasses four years beyond the immediate budget year.[18]
  - Each department's total operating budget is limited to the amount in the Three-Year Rate Plan. Each department may reallocate resources to line items within the budget.[19]
  - Once Financial Oversight has determined whether the budget conforms to the Rate Plan, the budget is provided to PSEG LI for consolidation. [20]

- Following consolidation of departmental budgets to a consolidated LIPA budget, LIPA Senior Management evaluates the proposed spending plan within the context of its alignment to the Authority's mission.[21]

- As discussed in Conclusion 15, LIPA has identified shortcoming in its Epicor financial system. As a result of limitations in Epicor, LIPA's budget process relies almost entirely on Excel to manually compile and present the budget.[22]

2. PSEG LI uses appropriate software in its capital and O&M budgeting processes; however, it relies on a manual, Excel-based process to transfer data between systems.

- The PSEG LI Planning and Budgeting (P&B) team uses the Profitability and Cost Management (PCM) System as its data warehouse and reporting system for the development of the operating and capital budgets.

  - For the operating budgets, the P&B analysts complete Excel templates to load budget data such as headcount, labor allocation, and non-labor expenses by cost center.
  - For the capital budgets, Business Work Planners provide capital information to the P&B Budget Analysts, who then upload the data into PCM.[23]

- Once the budget is complete in the PCM system, the data is downloaded and formatted on an Excel file which is uploaded to PSEG LI's SAP business management software system.

- As discussed later in this Chapter, T&D compiles its capital project budget information in a MicroStrategy database.

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[16] DR 172 Attachment CFO budget message

[17] DR 174 Attachment

[18] DR 172 Attachment CFO budget message

[19] DR 172 Attachment CFO budget message

[20] DR 174 Attachment 2

[21] DR 174 Attachment 2

[22] DR 271 Attachment 1

[23] DR 175

3. PSEG LI uses an effective process to develop its operating and capital budgets. The target budget amounts are based on the approved rate plan. PSEG LI uses a zero-based approach to develop budgets at cost center and project levels.

- PSEG LI's budget procedure, "Budget Process Documentation" was issued on February 9, 2017. It addresses the processes for budgeting PSEG LI's headcount, expenses (labor and non-labor), and capital.[24] The process documentation contains detailed steps regarding data sources, input processes and reports.

- The PSEG LI Operating Budget includes the operating costs associated with the following PSEG LI functional areas and programs:

  - T&D,
  - Customer Services,
  - Shared Services,
  - Power Markets,
  - Energy Efficiency and Renewable Energy Programs.

- The PSEG LI's Capital Budget includes costs from the following functional areas:

  - T&D,
  - IT,
  - Customer Service,
  - Facilities, and
  - FEMA.

- PSEG LI's P&B Group is responsible for budget preparation.

  - Seven Budget Analysts work with PSEG LI functional areas to ensure budget data is accurate and submitted on a timely basis.
  - A Budget Coordinator is responsible for budget templates, data distribution and organization and maintaining the budget timeline.[25]

- Each PSEG LI functional area has a budget liaison who is the primary budget contact for budget development.

- Budget analysts work with business budget liaisons to complete the templates for each of the cost elements and to ensure the accuracy of the budget information throughout the process.

- **Exhibit V-7** provides the primary cost types and process controls employed in the budget preparation.

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[24] DR 173 Attachment 1

[25] DR 173 Attachment 1 and DR 1

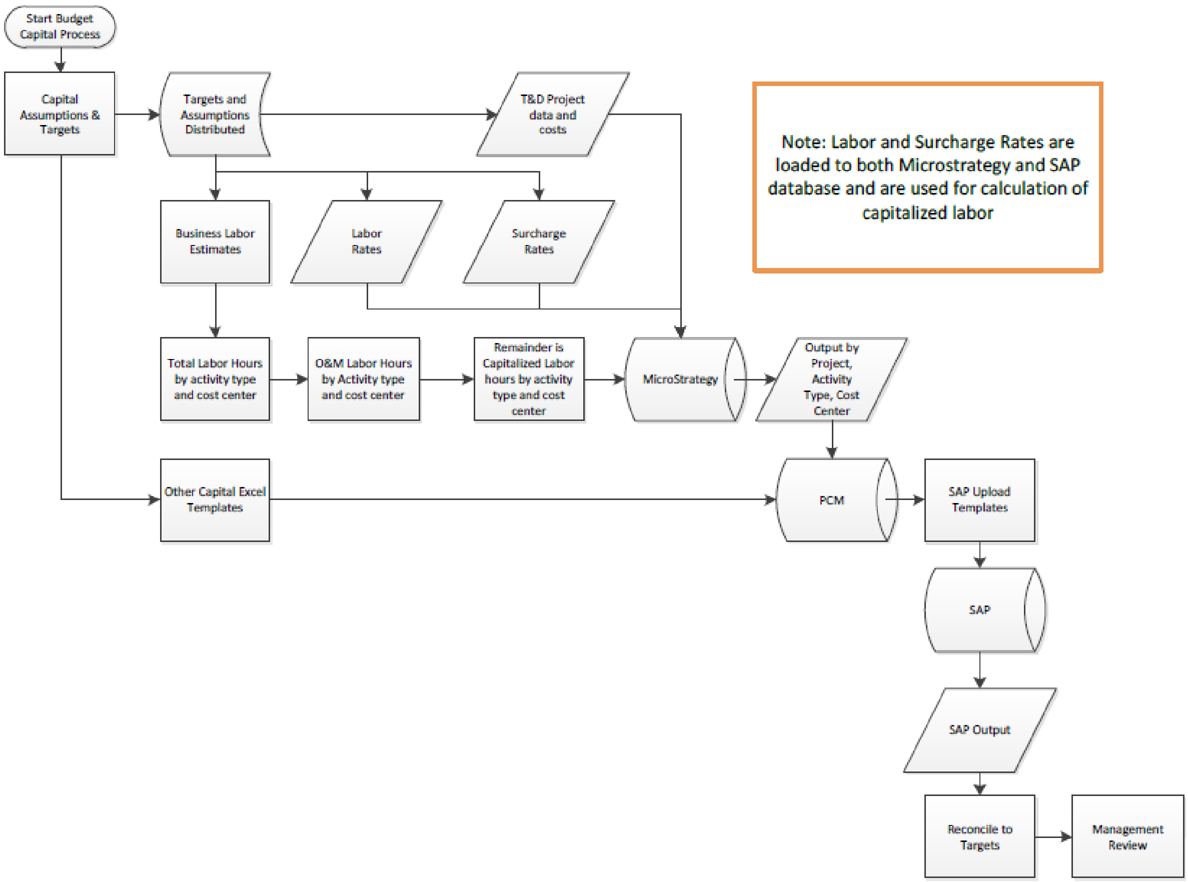
Exhibit V-7
Budget Cost Elements and Process Controls

Cost Types	Budget Process Controls
Labor	
▪ **Labor Assumptions** – Labor Rates from Human Resources are loaded in PCM and SAP ▪ **Labor Increment** – Percent changes in labor by cost by month for each business. ▪ **Headcount Budget** – Headcounts by month. Template starts with historical data ▪ **Part Time Employees** - Staffing Sheet template by cost center/activity type ▪ **Overtime** – Overtime percent by cost center/activity type by month and overtime rate multiplier ▪ **Fringe by VP** – Fringe allocation percentage is created by the Business Analyst Manager using data from Corporate benefits.	**Headcount Reconciliations** – (PCM vs Targets). PCM generates three reports: - Headcount mismatch - incorrect activity type - Staffing report **-** HR vs Planned count - Statistical Key Factor Report - reconcile to budgeted headcount by activity type **Labor Reports** - Overtime Hours - cost center and activity - Staffing Report - headcounts by cost center and activity - Activity Comparison - activity rates per cost center compared to last year - Capacity - net available hours by cost center by activity type - Labor Allocation - net capacity hours broken down by cost center by activity type by order/WBS - Non-Productive - by cost center by activity type
Non-Labor	
▪ Material, Outside Services and Other Budget O&M (MOO) – by cost element by month ▪ Affiliate Charges -- Calculated at the corporate office in NJ. Estimates used for budgeting as final changes not available until December.	**PCM MOO Expense Report** – Used to ensures PCM totals match template
Additional Verification Steps during Budget Development	
PCM Processing – Review of Output – Data in budget format to compare to targets using lookup tables **Cost Element Review** - a Cost element owner who ensures activity costs are aligned with correct organization. **Review of SAP Budget** - Headcount and staffing in SAP - Fringes - Incentive compensation	
Capital	
T&D Capital - Micro Strategy data uploaded to PCM **Other Capital** – Excel template data updated to PCM following review by Budget Analyst **Capitalized labor** calculated in PCM by hours, project and activity type.	**T&D –** Perform data validation against targets using Micro Strategy and the Project Workbook. **Other Capital** - Budget Coordinator validates capital data information between approved targets and PCM database capital data.
Assessments (allocation of overhead and support costs)	
The cost element groups used to calculate the allocations may be comprised of: ▪ Labor dollars based on Activity Type ▪ Labor and certain outside service dollars ▪ Material valued and non-valued dollars	**Verification of Cost Elements** - Budget ensure the list of cost elements utilized by business should receive assessment overhead or residual charges. **Verification and WBS** - Budget Analysts ensure the Order and WBS Groups are aligned properly by business.

Source: DR 173 Attachment 1

- **Exhibit V-8** presents an overview of PSEG LI's capital budget compilation process.

Exhibit V-8
Overview of Capital Budget Compilation Process



Source: DR 173 Attachment 1

- For each business the starting point is the capital target amount that was approved by Senior Management and aligned to the LIPA BOT approved targets.
- T&D compiles its capitalized labor and project cost data in the MicroStrategy database, and uses MicroStrategy to ensure labor hours are allocated to the correct Blankets, Projects and/or Specific work plans and to develop labor costs for each project. The output of the MicroStrategy analysis is costs by project, activity type and cost center. The P&B Budget Coordinator then uploads this data into PCM.
- Other businesses compile capital data by cost center and project in an Excel template and forward it to Budget Analysts for review and processing.[26]

- In addition to the validations completed by the budget analysts and budget coordinator for each PSEG LI business, a Senior Budget Analyst performs an overall

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[26] DR 173 Attachment 1

PSEG LI Budget reconciliation to provide an independent data validation against controlled documents (Rate Case and LIPA BOT-approved Targets).

  - **PCM vs Approved Budget Targets** – Approved Budget Targets are supplied during and/or as a result of the Budget Kick-Off meeting. Throughout the budget process to build the Labor, Non-Labor, Headcount, Capital budget, PCM reports are generated to compare the budget to approved target amounts. This reconciliation is conducted by a PSEG LI Senior Budget Analyst each time PCM reaches a target milestone and prior to initial SAP submission.
  - **PCM vs SAP reconciliation** – This reconciliation is conducted to ensure PCM and SAP budget data are synchronized by business at the initial SAP loading.
  - **SAP vs BOT reconciliation** – PCM budget data is used to develop the budget for review by the LIPA BOT. After the BOT approves the budget, the budget is loaded into SAP and compared to the BOT budget to ensure the SAP budget is correct.[27]

4. **PSEG LI appropriately began to implement a new capital project optimization process in 2017. It is too early to determine the effectiveness of the process. LIPA is not directly involved in the SOS capital project optimization process as PSEG LI is responsible for the development of capital project budgets.**

- In late 2016/early 2017, PSEG LI began to change its project prioritization approach from a spreadsheet-based approach to the use of UMS Group's Spend Optimization Suite (SOS). The UMS Group's SOS is used by several utilities, including American Electric Power, Sacramento Municipal Utility District, and United Illuminating.[28] PSE&G, PSEG LI's utility affiliate in New Jersey, has used SOS for several years.

- LIPA is not directly involved in the SOS capital project optimization process. PSEG LI is responsible for the development of the project-related capital budgets for T&D, Customer Operations, and Information Technology.

- PSEG LI plans to use SOS to support its asset management decision processes; from identifying and prioritizing the risks and benefits, to analyzing investments and, ultimately, optimizing the portfolio of capital projects.[29]

  - The portfolio optimization techniques used by SOS differ from simple prioritization techniques wherein projects are prioritized based on a value score, and the selected projects are those with the highest value score above a particular budget cut-off line.
  - In contrast, SOS optimization selects the optimum bundle of projects that maximize strategic values for minimum cost. The strategic value contribution of each project is measured within the bundle.[30]

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[27] DR 173 Attachment 1

[28] http://ums.zookini.nl/Cms_Data/Contents/UMSDB/Media/productpdfs/SOS-Case-Studies.pdf

[29] DR 66

- The SOS tool scores projects in accordance with how they meet Strategic Objectives, and the Success Criteria that underlie each Strategic Objective. SOS determines the value impact of funding the project and the risk impact of deferring the project based on answers to questions regarding each criterion. A specific project may not meet all strategic objectives, but must be scored in a least one value and risk category, or it will be deferred as not providing any value or mitigating any risk.[31]

    - For the value score, each project is scored on a -5 to 5 scale on the value that it would contribute to each success criterion measure. The weighted values are then summed.
    - For the deferral risk score, the score is the metric of the consequence of not doing the project and the probability the consequence happening. Multiplying both of these numbers generates a risk score. The risk score ranges from 0 to 25. The higher the number, the riskier it is for the business if the investment is deferred. Overall risk is calculated as the highest consequence x probability combination. [32]
    - Each project may also be classified as "mandatory." In SOS there are three types of mandatory investment: 1) Legal, 2) Minimum–Required to ensure basic utility service or essential to safe and reliable operation, and 3) Forced Priority–Typically used for existing projects that must be completed.[33]

- To support the use of SOS, PSEG LI established a new Investment Delivery Assurance (IDA) group in the Planning, Resources and Engineering department within T&D; this six-person group has been fully staffed since December 31, 2016.[34]

- The SOS optimization process is also supported by PSEG LI's T&D Management group, which consists of directors from the following organizations:

    - Planning
    - Transmission Operations
    - Project and Constructing
    - Asset Management

- During the first half of 2017, the IDA group, along with UMS consultants, trained users on the use of SOS, and the end-users loaded T&D project data into the SOS system.

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[30] DR 957 Attachment 1
[31] DR 502 Attachment 1.
[32] DR 957 Attachment 1
[33] DR 502 Attachment 2
[34] DR 2 Attachment 2, and DR 66

5. While PSEG LI's use of SOS to optimize T&D project selection for the 2018 capital budget is a good start and the effort has led to improvements in the quality of project data, SOS is not yet fully implemented and procedures are still under development.

- PSEG LI used SOS to optimize the portfolio of T&D projects included in the 2018 capital budget, and plans to expand to additional lines of business, including Customer Operations and Information Technology in future years.[35]

- Before IDA could run SOS scenarios, it was necessary to improve the quality of the project data, to eliminate duplicate projects and correct cash flow projections.[36] IDA also requested that departments remove some of the projects that were proposed but had virtually no chance of approval in order to decrease the number of projects included in the SOS optimization.

- The Strategic Objectives and Success Criteria used for the T&D 2018 project selection are shown in **Exhibit V-9**.

Exhibit V-9
SOS Strategic Objectives and Success Criteria Weightings
Used in Process to Select T&D Projects for 2018 Capital Budget

Strategic Objective	Weighting	Success Criteria	Weighting
Economic	15%	Qualitative Assessment of Economic Recovery	100%
People	10%	Human Work Environment	50%
		Physical Work Environment	50%
Green	10%	Environmental and Business Ops	25%
		Renewable Energy Generated	25%
		Efficiency Savings	25%
		Fleet Miles per Gallon	25%
Safe, Reliable	65%	Customer Service and Ops	6%
		Asset Health & Condition	15%
		SAIFI	20%
		MAIFI	14%
		CAIDI	12%
		JD Power – Electric	12%
		PSC LIPA Inquiries	15%
		Asset Operations & Proficiency	6%

Source: DR 957 Attachment 1.

- The Strategic Objectives and their Success Criteria weightings continued to be under review after the 2018 budget process.[37] The SOS model contains additional success

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[35] DR 957 Attachment 1

[36] DR 966

[37] DR 957 Attachment 1

criteria that were not used for the 2018 budget, such as the project's NPV and the financial risk of deferral.[38]

- Each project also has a risk score, a metric for the consequence of not doing the project. The risk score reflects the potential impacts of deferring the project and the probability that these impacts will occur.[39]

- As explained by PSEG LI, SOS is a support tool, not a model. It is meant to augment the expertise and experience of the decision makers, not to replace good judgement.[40]

- The actual project selection process is a combination of PSEG LI management's review and ranking of projects and SOS optimization scenarios. The general process for the T&D project optimization for the 2018 budget was as follows:

  – IDA ran four SOS optimization scenarios and identified projects that were deferred, optimized or partially funded under each scenario:

    - Value Optimization,
    - Risk Minimization,
    - Optimization with Mandatory Projects, and
    - Optimization without Mandatory Projects.

  – In a separate effort, the T&D Management Group ranked each project from 1 to 4, with 1 being mandatory. Ultimately the T&D Management Group classified each project as "optimized" or "deferred".
  – IDA performed a "pairwise" comparison and grouped different combinations of T&D Management Group and SOS optimization results. The results are summarized in **Exhibit V-10**.
  – The 2018 T&D capital budget target is $423 million. As shown in **Exhibit V-10**, projects in Groups A to C were optimized by both T&D Management and certain SOS scenarios, and total $415 million. Projects in Groups D to G received conflicting optimized or deferred scores by T&D Management and SOS, and were re-reviewed by the T&D Management to select an additional $7.5 million projects to meet the $423 million budget target. Projects in Groups H and I were deferred.

- PSEG LI considers its use of SOS for the 2018 budget to be a test run. PSEG LI and LIPA Internal Audit have identified opportunities for improvement, including the following:

  – Review and adjust the project description questions.

    - Add a demographic category for "permitting required", which can act as a flag of sorts when running optimization scenarios.

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[38] DR 502 Attachment 1 and DR 957 Attachment 2
[39] DR 957 Attachment 1
[40] DR 957 Attachment 1

    - Flag projects that are necessary to remediate a violation or to prevent a violation.

- Review the scoring criteria for each business area when setting up a new project in SOS.
- Identify any biases toward certain types of projects.
- Refine the Strategic Objectives and the Success Criteria.[41]

Exhibit V-10
2018 T&D Project Optimization Process Results

Group	"Pairwise" Comparison Grouping Description	Number of Projects	2018 Projected Spending	Disposition
Optimized				
A	Investment is confirmed in T&D Management ranking process, all scenarios in SOS.	69	$271,667,246	$415.5 million confirmed for funding in 2018.
B	Investment is confirmed in T&D Management ranking process, and optimized in SOS Mandatory scenario with blanket constraint of $202 million.	14	95,979,001	
C	Investment is confirmed in T&D Management ranking process, and optimized in three SOS scenarios with blanket constraint of $202 million.	7	47,804,000	
Further Review Required				
D	Deferred in at least 2 scenarios in SOS but not deferred in T&D Management ranking process.	10	$3,825,003	Projects reviewed by Management Team which selected $7.5 million of projects to meet the $423 million budget target.
E	Optimized in all SOS scenarios but deferred per T&D Management ranking process	41	41,006,627	
F	Optimized in two or three scenarios in SOS but deferred as per T&D Management ranking process	10	10,080,000	
G	Investments that are proposed by T&D management but had no Cash Flows in SOS due to timing	5	1,284,000	
Deferred				
H	Deferred in all scenarios including T&D Management ranking process	2	$2,375,000	Not funded in 2018
I	Deferred as per T&D management ranking process and in at least two SOS scenarios.	41	29,391,621	

Source: DR 957 Attachment 2 and DR 966 Attachment 1.

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[41] DR 957 Attachment 1 and DR 904 Attachment 17

6. **While PSEG LI includes depreciation expenses associated with new capital in the budgeting process, PSEG LI does not have a formal process to include incremental O&M expenses associated with new construction in its budgets.**

   - PSEG LI forecasts depreciation expenses associated with new capital in its budget model.

     - On an annual basis, PSEG LI's Plant Accounting group provides current and historical depreciation data, and works with the Budget Planning group to assist in forecasting the expected "new capital additions to plant" for the upcoming year.
     - The forecasted new capital additions consider the approved capital budget, assets expected to be capitalized and expected date the assets will be placed into service.
     - These data are used to forecast next year's depreciation in the budget model.[42]

   - PSEG LI's budget procedure does not address the need to determine whether there are other incremental O&M associated with new capital installations.[43] It is important to identify all incremental O&M so that they can determine if the operating budget can support all necessary expenditures.

7. **PSEG LI's Planning and Budgeting Group issues monthly capital and operating variance reports and follows up with the business areas to determine the causes of the variances.**

   - The Monthly PSEG LI Flash Reports track variances.

     - Day 5 – Variance data is distributed to the various business units (preliminary flash).
     - Days 6 to 9 – Finance Department works with each business unit to identify the causes of variances.
     - Day 10 – Reports are issued to LIPA Finance and Financial Oversight departments.
     - Day 14 – Reports are issued to the Senior Leadership Team (composed of PSEG LI Internal Audit and LIPA VP of Financial Oversight).[44]

   - Flash reports are compiled and go into the monthly package for the Finance & Audit (F&A) Committee of the BOT.

   - PSEG LI has a monthly meeting to review O&M budget results.[45]

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[42] DR 177
[43] DR 173 Attachment 1
[44] IR 128
[45] DR 903

8. **LIPA has recently enhanced its oversight of PSEG LI's operating expenses.**

- In late 2016, LIPA hired a Director of Financial Oversight who is responsible for analysis of PSEG LI revenue and expenses to ensure: the integrity of financial results, that performance is within prescribed targets, and that the operating and capital budgets are appropriately prepared. His budget oversight-related responsibilities include:

  - Coordinating with PSEG LI to ensure timely operating and capital budgets and five-year forecasts.
  - Analyses regarding the financial implications of PSEG LI's proposed budgets, requested budget amendments, and cash funding requests.
  - Monthly and annual analysis of actual results against budgets for LIPA and PSEG LI.[46]

- In 2017, LIPA requested that PSEG LI make improvements to its monthly O&M variance flash reports.

  - In accordance with the A&R OSA, PSEG LI submits a monthly O&M and Capital flash report to LIPA via email by the 10th business day of the month.
  - LIPA recently asked that the report include a summary section, as well as verbal explanations for significant variances.[47]

- LIPA also asks follow-up questions regarding the variance reports.

  - LIPA reviews the flash report and contacts PSEG LI Planning & Budgeting with comments and questions, if any.
  - Planning & Budgeting analysts then work with the line of business to answer the additional questions and prepare a more in-depth explanation.[48]
  - NorthStar's review of correspondence shows that LIPA had follow-up questions on reports, and that PSEG LI adequately responded to those questions.[49]
  - In 2017, LIPA requested a mid-year meeting review to understand spend drivers for unfavorable variances.[50]

9. **The roles and responsibilities of the Board and LIPA senior management in budget preparation, approval and oversight are appropriate given that PSEG LI has primary responsibility for budget preparation and oversight.**

- As part of the annual budget cycle, PSEG LI and LIPA senior management review the O&M and capital budgets proposed by PSEG LI in September and October before

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[46] DR 683 Attachment 1
[47] IR 127
[48] DR 903
[49] DR 678
[50] DR 903

the consolidated budget is first presented to the Board and the public in November. LIPA's CFO has overall responsibility for the consolidated O&M and capital budget.

- LIPA senior management has specific responsibilities for budget preparation and approval as follows.
  - Each LIPA VP is responsible for the development of his/her departmental budget.[51]
  - The CFO is responsible for the development of the interest expense, debt service, and the UDSA budget.[52]
  - The VP of Operations Oversight is responsible for the review of the PSEG LI O&M and Capital budgets for T&D Operations, Customer Operations, Energy Efficiency and Power Markets.[53]
  - LIPA's VP of Financial Oversight is responsible for the review of the PSEG LI O&M and Capital budgets.[54]
- The Board's Finance & Audit (F&A) Committee is responsible for advising the Board with respect to the proposed operating and capital budgets. The committee is also responsible for monitoring LIPA's budget compliance (actual versus budget) on at least a quarterly basis (current practice is to send these reports monthly), and reporting to the Board as appropriate.[55] Each November, there is a Board Budget Workshop on the proposed budget for the next year, prior to the Board's approval of the budget in December. [56]
  - LIPA and PSEG LI senior management present the Board with extensive detail for all elements of the consolidated budget.
  - Board members can ask questions about budget items.
- In accordance with its by-laws, the Board has the responsibility to adopt O&M and capital budgets to support LIPA's operations. The Board is not responsible for the development of the budget, nor is the entire Board responsible for budget oversight.
- Under the terms of the A&R OSA, the Board and LIPA have limited authority to modify the PSEG LI budgets.
  - PSEG LI and LIPA budgets are based on the Three-Year Rate Plan developed through an evidentiary process.
  - The BOT and LIPA management do not have the authority to modify the annual budgets prepared by PSEG LI except through the dispute resolution process.

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[51] DR 170

[52] DR 170

[53] DR 170

[54] 2017 LIPA/PSEG LI Fact Verification

[55] DR 170

[56] DR 173 Attachment 1

  - It has been the practice of the BOT to approve and amendments to approved budget amounts that are proposed by PSEG LI.
  - If, following discussions with LIPA, PSEG LI disagrees with any determination made by LIPA or the Board regarding the Consolidated LIPA Budget, these disagreements are subject to dispute resolution.[57]

- NorthStar attended the workshop session for the 2018 budget. Consistent with the Board's minimal role in approving the budget, while the entire Board is invited to the workshop, only three members attended and asked questions of management.

  - In accordance with the A&R OSA, PSEG LI has complete flexibility, subject to prior consultation with, but not subject to approval by, LIPA, to (i) reallocate or postpone expenditures within the approved Operating Budget, (ii) reallocate or postpone expenditures within the approved Capital Budget and (iii) reallocate between the approved Operating Budget and the approved Capital Budget in order to address changed operational or commercial circumstances or new legal or regulatory requirements.[58]

10. **The F&A Committee receives adequate data to monitor budget performance on a monthly basis, with the exception of LIPA-specific capital expenditure data, which is not included in the monthly F&A package.**

- LIPA's Finance department prepares a detailed monthly package which is presented to the Board's F&A Committee. The F&A Committee package is a power-point presentation that includes the LIPA and PSEG LI financial reports listed in **Exhibit V-11**.

- The F&A Committee does not receive monthly reports of LIPA's actual vs. budgeted capital expenditures. LIPA-specific capital variance is only reported to the Board annually as part of the budget package. As previously noted in Exhibit V-6, the LIPA-specific capital expenditure 2017 budget (including $22.5 million for Nine Mile 2) represented only 5 percent of the consolidated PSEG LI and LIPA budget.

- LIPA and PSEG LI senior management present the F&A Committee package at F&A committee meetings and respond to any questions from the committee members.

11. **LIPA submits budget amendments recommended by PSEG LI to the BOT for approval.**

- In accordance with the A&R OSA, PSEG LI may request an amendment to the Board-approved budget when there are reasonably unanticipated events or additional

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[57] DR 4 Attachment OSA, p. 52

[58] DR 4 Attachment OSA

requirements imposed by LIPA which have resulted (or are expected to result) in schedule delays or increased work scope or costs.[59]

- In accordance with the A&R OSA, PSEG LI submits a budget amendment request to LIPA Senior Management for review and approval.[60]
- The Board approves budget amendments.[61]
  - The A&R OSA states that "If LIPA agrees that such expenditures are required…such expenditures shall then qualify as Non-Storm Emergency Expenditures, whereupon LIPA shall either (i) approve as promptly as practicable the proposed budget amendment…or, (ii) permit the Service Provider [to include amounts in future budgets.]
  - LIPA interprets this section of the A&R OSA to require that the Board review and approve all budget amendments.[62]

Exhibit V-11
Monthly F&A Package Reports

Report	Details	Source
Consolidated Results (Actual and Budgeted amounts)	• Revenues • Power Supply Charge • Rev. Net of Power Supply Charge • PSEG LI Managed and Operating Costs • LIPA Expenses • Changes in Net Position	LIPA Accounting
LIPA Managed Costs (Actual and Budgeted amounts)	• Operating Expenses • Depreciation • Amortization • Interest	LIPA Accounting
LIPA Managed Professional Services (Actual and Budgeted amounts)	• Legal • Accounting and Audit • Engineering/Strategic Planning/Contract Oversight • Financial Advisor/Cash Management • Other	LIPA Accounting
LIPA Liquidity Position	• Days Cash on Hand	LIPA Treasury
LIPA Consolidated Statement of Net Position	• Assets and Liabilities	LIPA Accounting
PSEG LI Managed Costs (Actual and Budgeted amounts)	• Assessments • Losses on uncollectible accounts • Utility depreciation, Revenue • Property taxes • Storm restoration	PSEG LI Finance

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[59] DR 783

[60] DR 783

[61] LIPA/PSEG LI 2017 Fact Verification Package

[62] LIPA/PSEG LI 2017 Fact Verification Package

Report	Details	Source
Revenue Variance Analysis (Actual and Budgeted amounts)	• Revenue • Power Supply Charge • Sales of Electricity	PSEG LI Finance
PSEG LI Capital Expenditures (Actual and Budgeted amounts)	• T&D • FEMA • Other	PSEG LI Finance
PSEG LI Major Capital Expenditures Over $25 million	• Original Cost Estimate • Current Cost Estimate • Actual Costs to Date	PSEG LI Finance
Hedge Program Summary Report	• Hedge Ratio • Mark-to-Market • Summary of events	LIPA Risk Management

Source: DR 741.

12. PSEG LI has a strong financial incentive through the A&R OSA to control aggregate spending. If aggregate spending exceeds the budget (for capital and operating) by more than 2 percent, PSEG LI does not earn any of its incentive compensation. PSEG LI has authority to adjust spending on individual projects during the course of the year which can be an aid in achieving aggregate spending.

- The A&R OSA provides for annual incentive compensation of $5.44 million in 2014 and 2015 and $8.7 million annually thereafter provided that PSEG LI meets its performance metrics. These amounts are stated in 2011 dollars and are adjusted to the current year for inflation.[63]

- As stated in the A&R OSA:[64]

> "The Service Provider shall have complete flexibility, subject to compliance with the Contract Standards and prior consultation with, but not subject to approval by, LIPA, to (i) reallocate or postpone expenditures within the approved Operating Budget, (ii) reallocate or postpone expenditures within the approved Capital Budget and (iii) reallocate between the approved Operating Budget and the approved Capital Budget in order to address changed operational or commercial circumstances or new legal or regulatory requirements."

13. LIPA does not have unlimited access to funds or financing opportunities. Near-term budget limitations and projected expenditures for multi-year projects included in the 2018 capital plan could constrain LIPA's ability to fund new projects.

- The 2018 T&D capital budget of $423 million was recommended to the LIPA Board in the DPS Recommendation that was approved by LIPA's Board in December 2015.

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[64] DR 4 Attachment OSA O&R 2013, Page 43

- For the 2018 Budget, PSEG LI proposed a total of 199 projects with projected expenditures of $503 million in 2018. Proposed projects exceeded the T&D $423 million target budget by $80 million. In order to keep within the budget limit, many projects were not approved.[65]

- While budgets are approved one year at a time, and include projections for the following year, only the results for 2018/2019 are available at this time. If budgets for the next several years will be at the same level as the 2018 budget and the 2019 projected budget of $488 million, further deferrals of projects would be anticipated.

- Projects that have been approved for 2018 will require continuing expenditures in 2019 that will consume virtually all the available budget anticipated. In accordance with LIPA's current five-year T&D capital plan, 99 percent of the proposed investments for 2019 are multi-year investments that started in 2018 or prior years.[66]

Financial Reporting

14. Due to limitations in LIPA's financial system, the process to prepare financial statements and reports is highly manual and the data in LIPA's financial system do not provide adequate detail for the analyses needed to support effective oversight.

- On a monthly basis, LIPA's Finance Department performs account reconciliations, posting of journal entries, and financial statement account analyses to execute the financial statement close process using Epicor General Ledger software.

- Epicor has little customization and the majority of accounting activity is manually posted to the general ledger on a monthly basis.

- An overview of the consolidated budget and financial reporting process is shown in **Exhibit V-12**.

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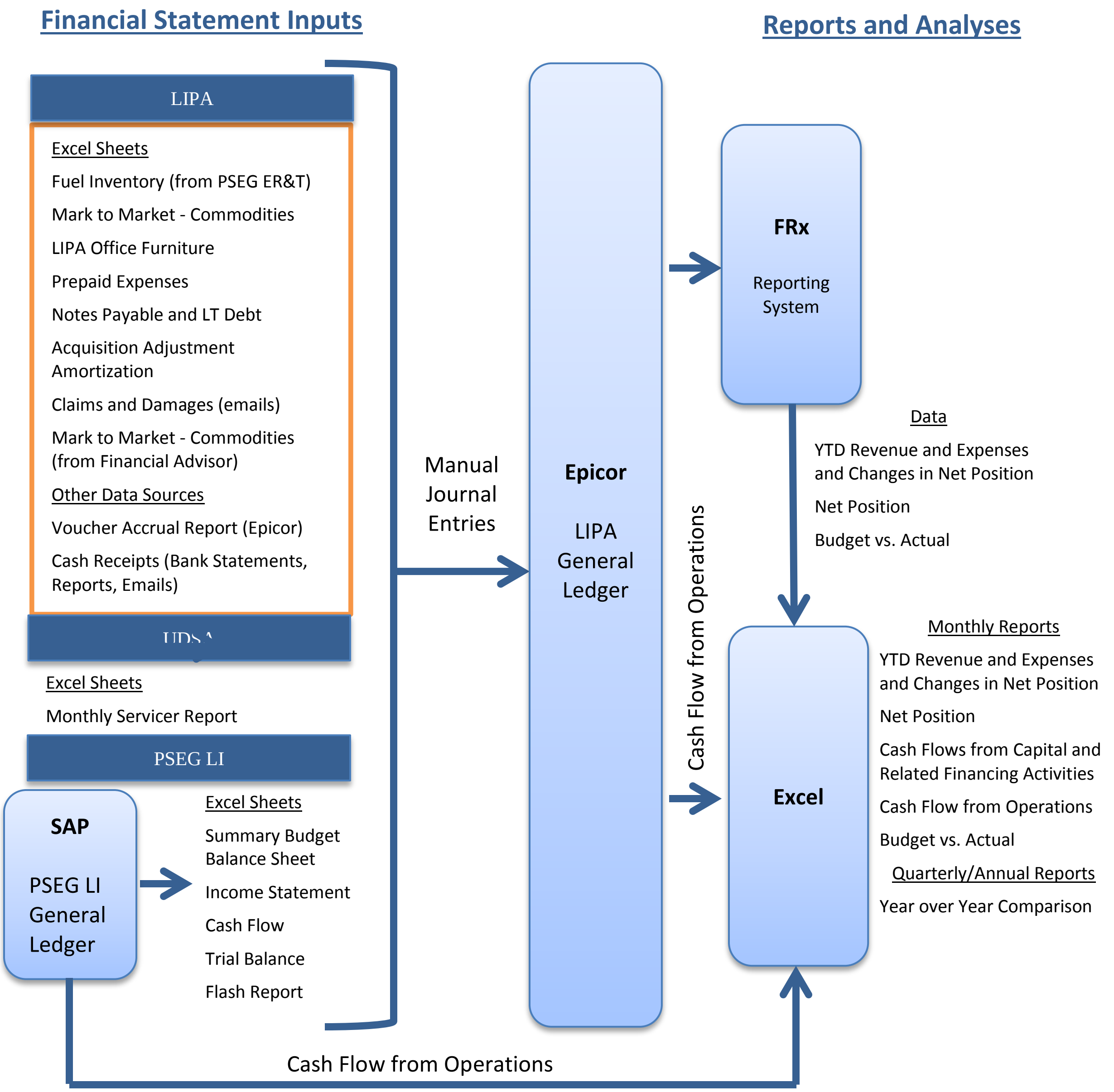
[65] NorthStar analysis of data in DR 957 Attachment 2

[66] DR 966

Exhibit V-12
Consolidated Financial and Budget Reporting Process



Source: DR 269.

- The current tools and processes used to transmit budget and accounting data from PSEG LI to LIPA's financial system are inadequate and need improvement.[67]

  - PSEG LI maintains its own financial records in SAP and provides information to be included into LIPA's general ledger for consolidated reporting. The information is consolidated at a summary level without visibility into the detailed transactions and manually input.[68] Information given to LIPA includes a balance sheet, income statement, cash flow statement, account reconciliations, a Flash Report (Actual vs. Budget variance analysis) and F&A Committee Report (with variance explanations).[69]
  - PSEG-LI maintains a single O&M code item with no breakdown into department codes. The LIPA accounting department uses a management flash report to further define the allocation for the intercompany entry for O&M.[70]
  - LIPA's controller's group performs a formal review and posting process to manually enter journal entries using reports provided to LIPA's accounting department from various sources at LIPA and PSEG LI.[71]

- Inadequacies in the Epicor system require manual work-arounds to provide the detailed information for consolidated reporting, as well as the ability of LIPA personnel to drill down in its accounting system to follow-up on financial issues.

  - Epicor does not have the detailed cost and unit data necessary for performing the analyses to effectively manage PSEG LI's and its own performance.
  - It is necessary for LIPA personnel to access the SAP system to obtain detailed information.

15. LIPA recognized the limitations in its financial system in 2015, and has gathered information on possible enhancements, but has not completed the process to replace or improve the system.

- In 2015 and early 2016, LIPA investigated options for improving its Enterprise Resource Planning (ERP) systems.

  - LIPA first considered a LIPA-only ERP system, and later considered placing LIPA on a common platform (e.g., SAP) with PSEG LI.
  - With the assistance of an outside consultant, LIPA developed a set of high-level user requirements and performed a gap analysis.
  - LIPA and its consultant identified four possible options to replace its financial system.[72]

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[67] DR 271 Attachment 2
[68] DR 271 Attachment 2
[69] DR 904 Attachment 9
[70] DR 271 Attachment 2
[71] DR 271 Attachment 2
[72] DR 271

- While investigating options to replace Epicor, questions arose regarding the use and ownership of intellectual property rights. The development of an overall ERP strategy was tabled pending further discussion and resolution of the intellectual property issues.[73]

- As of November 2017, LIPA was continuing its effort to replace its financial system, and plans to intensify this effort when it hires a new Chief Information Officer (CIO).[74]

16. **LIPA Internal Audit (IA) periodically reviews the controls around PSEG LI's/LIPA's financial systems. With the exception of LIPA's manual processes to consolidate the financial statements, LIPA's IA found no control issues regarding the financial systems.**

- LIPA Internal Audit has performed several reviews of the LIPA and PSEG LI financial systems as listed in **Exhibit V-13**.

- The 2016 audit of LIPA's internal controls identified no issues associated with LIPA's chart of accounts, but did note that LIPA could implement controls to strengthen the voucher approval process.[75] NorthStar did not perform an independent test of LIPA's internal controls.

- The 2016 audit of PSEG LI's SAP financial reporting found PSEG LI's controls to be adequate.[76]

Exhibit V-13
LIPA Internal Audit of LIPA and PSEG LI Financial Systems

Year	Audit	Summary of Observations/Response
2014	Review PSEG LI compliance with financial account reconciliation requirements in the A&R OSA.	LIPA did not receive PSEG LI General Ledger Account Reconciliations on time or in the proper format. PSEG LI established account reconciliation review policy and added new staff with experience and the skill set to perform the task.
2015	LIPA/PSEG LI Financial Statement Close Process	LIPA can implement controls to strengthen the current process for reviewing outstanding checks and eliminating the manual intervention required to consolidate the financial statements. The dollar amount of the outstanding checks is immaterial; less than $370,000 and LIPA took steps to address the outstanding check issue. LIPA is in the process of replacing its current Enterprise Resource Planning (ERP) system which will eliminate the manual intervention required to consolidate the financial statements.

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[73] DR 271
[74] IR 219
[75] DR 904 Attachment 13
[76] DR 904 Attachment 11

Year	Audit	Summary of Observations/Response
2016	SAP Financial Reporting	Controls evaluated are adequate, appropriate and effective to provide reasonable assurance that risks are being managed and objectives will be met.
2016	LIPA Internal Control Testing of Key Controls	Audited key controls for the following LIPA processes for the period January 2016 - December 2016: ▪ Accounts Payable ▪ Budgeting ▪ Cash Flow ▪ Chart of Accounts ▪ Debt Management ▪ Derivatives ▪ Employee Expenses ▪ General Accounting & Financial Reporting ▪ Human Resources and Payroll ▪ Minority Women-owned Business Enterprise ▪ Procurement ▪ Treasury The audit identified no reportable control deficiencies, but noted that LIPA could strengthen the voucher approval process.

Source: DR 35.

- The 2015 audit of the PSEG LI/LIPA financial close process identified LIPA's manual intervention to consolidate the financial statements as a control issue, but noted that "LIPA is in the process of replacing its current Enterprise Resource Planning (ERP) system which will eliminate the manual intervention required to consolidate the financial statements."[77]

D. RECOMMENDATIONS

1. Continue to develop and implement the SOS capital program optimization model.

   - Implement improvements identified by PSEG LI and LIPA Internal Audit, including:

     – Review and adjust the project description questions.

       - Add a demographic category for "permitting required", which can act as a flag of sorts when running optimization scenarios.
       - Flag projects that are necessary to remediate a violation or to prevent a violation.

     – Review the scoring criteria for each business area when setting up a new project in SOS.
     – Identify any biases toward certain types of projects.
     – Refine the Strategic Objectives and the Success Criteria. Consider including Success Criteria not used for the 2018 budget, such as NPV and the financial risk of deferral.

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[77] DR 904 Attachment 9

- Expand the use of SOS to other business areas, including IT and Customer Operations.

- Include a step in the SOS optimization process to calibrate value and risk scoring across business units that develop capital projects such as Network Strategy Planning group, Electric Operations, and Reliability Management. IDA should lead a process to review the scoring of projects with similar risk values to ensure the projects are scored on a comparable basis. Similarly, IDA should ensure the different organizations use comparable bases for value scoring the projects using the Strategic Objectives and the Success Criteria.

2. Provide LIPA-specific capital budget versus actual expenditure variance data to the BOT in each F&A Committee package.

3. Update the PSEG LI budget procedure to include the determination of incremental O&M expenses associated with new construction.

4. Complete the process of upgrading LIPA's financial system.

5. Determine the feasibility and cost of establishing interfaces between PSEG LI's MicroStrategy, PCM, and SAP systems to eliminate the need for manual data transfer processes. If cost effective, implement processes to allow electronic data transfer between the systems.

VI. DEBT MANAGEMENT

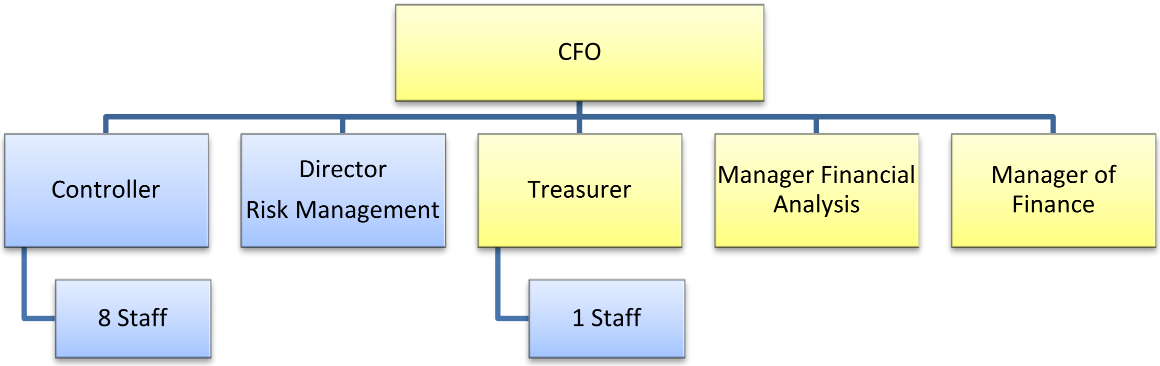
A. BACKGROUND

Utilities are capital-intensive entities that require significant investment in plant and equipment to maintain efficient and reliable service for customers. LIPA's 2016 Audited Financial Statements shows that LIPA's utility plant totals $7.8 billion and long-term debt at December 31, 2016 was $7.8 billion including Utility Debt Securitization Authority (UDSA) debt of $4.0 billion.

LIPA Debt Management Process

LIPA is responsible for managing the debt issuance process and providing capital to fund the utility's capital program. LIPA's Chief Financial Officer (CFO) has responsibility for the debt issuance process, with support from personnel both inside and outside LIPA. Key LIPA Finance personnel involved in the debt issuance process are highlighted in yellow in **Exhibit VI-1**.

Exhibit VI-1
LIPA Finance Organization [Note 1]
(Positions Involved in Debt Management are Highlighted in Yellow)



Note 1: The LIPA Finance organization handles financing and debt, and it differs from the Financial Oversight Department which oversees PSEG LI. The Financial Oversight Department is led by the VP of Financial Oversight and is not shown in this exhibit.
Source: DR 1

LIPA personnel with responsibilities for the debt management include:

- **Chief Financial Officer (CFO)** - Responsible for funding LIPA's capital plan. The annual budget includes amounts required to be funded by either short-term or long-term financing. Working in concert with other LIPA personnel and LIPA's outside Financial Advisor, the CFO evaluates options and develops the financing approach. The evaluation process examines the type of financing (short- or long-term) and use of LIPA's revolving credit facility, and may include reviewing proposals from investment and commercial banks.[1]

- **Manager of Finance** – Responsible for evaluating debt issuance plans within the existing capital structure. Working with LIPA's financial advisors, the Manager of Finance examines different approaches to determine the impact on LIPA's capital structure and budget of alternative financing plans. Once the financing plan is adopted, the Manager of Finance works with the CFO and the financing team to assemble the information required either for a public offering, a short-term financing or a draw on LIPA's revolving line of credit. The Manager of Finance also works with the CFO to assemble information for the rating agencies and investors, and participates in working group meetings with the underwriters and the financial advisor.[2]

- **Manager of Financial Analysis** – Works with the CFO to evaluate the impact of debt issuance plans on LIPA's cash flow as well as the overall capital structure. The Manager of Financial Analysis also review the impacts on LIPA's credit metrics (fixed obligation coverage, debt/capital, days cash on hand), and the long-term impacts of the financing. The Manager of Financial Analysis also is part of the financing team, working with the underwriter, bond and underwriter counsel and disclosure counsel.[3]

- **Treasurer** – Manages bank accounts where funds from bond sale are placed to fund the construction of capital projects, pay the cost of issuance and fund other required expenditures.[4]

LIPA's outside advisors and consultants provide support to its debt management process:

- **Underwriter** – Administers the public issuance and distribution of securities from an issuing body. The underwriter works closely with the issuing body to determine the offering prices. The underwriter buys the securities from the issuer (LIPA) and sells them to investors.[5]

- **Financial Advisor** - Assists on all financial matters, including the sale of bonds, the use of financial derivatives, debt management, credit ratings management, and other financial matters.[6]

- **Bond Counsel** – Responsible for making sure the Authority is compliant with LIPA's bond resolutions, the Board authorization and the various State requirements for debt issuance.[7] Renders a legal opinion on the validity of the bond offering, the security

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[1] DR 124
[2] DR 124
[3] DR 124
[4] DR 124
[5] DR 134 Attachment
[6] DR 134 Attachment
[7] DR 124

for the offering, and whether and to what extent interest on the bonds is exempt from income and other taxation.[8]

- **Disclosure Counsel** – Renders a legal opinion on the accuracy and completeness of the offering document.[9] Ensures continued compliance with the respective Authority changes and Board authorizations for those changes, and makes the required disclosures related to any offering of the authority. Disclosures are required by regulatory entities such as the Securities and Exchange Commission (SEC) and the Municipal Securities Rulemaking Board (MSRB).[10]

Rating agencies assess the creditworthiness of debt securities and their issuers. The Authority is monitored and rated by Standard & Poor's Ratings Services (S&P), Moody's Investors Service, Inc. (Moody's), and Fitch Ratings (Fitch).[11]

LIPA's Financial Policy

As part of its decision to implement the DPS' Three Year Department Rate Recommendation (DRR), the LIPA Board adopted a new financial policy on December 15, 2015. The current policy is designed to improve LIPA's financial position and obtain the lowest reasonable financing costs over both the short and long term.[12]

The new financial policy includes several components:

- **Adoption of the Public Power Model** – The Public Power Model recovers LIPA's operating expenses plus its debt service requirements.[13] As stated in LIPA's consolidated budget, the Public Power Model is used by nearly all of the country's major public power producers.[14] Unlike a traditional investor-owned utility revenue requirements model, the Public Power Model is cash-based. The Public Power Model does not recover non-cash expenses such as depreciation, amortization, and accrued interest expense. It defines the utility's revenue requirement as revenues needed to cover operating expenses, meet its debt service obligations and provide adequate coverage to: 1) provide bond holders and lenders an appropriate degree of confidence that all expenses and debt/finance payments can be paid; and, 2) provide an appropriate contribution towards new capital additions.[15]

- **Mid-A Ratings Target Over Five Years** – At the time of the Rate Plan filing, the Authority had credit ratings of Baa1 (stable outlook), A- (negative outlook), and A- (negative outlook) (Moody's/S&P/Fitch), which were the lowest of the large

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[8] DR 134 Attachment
[9] DR 134 Attachment
[10] DR 124
[11] DR 134 Attachment
[12] Matter No. 15-00262, LIPA and PSEG LI, Department Rate Recommendation (DRR) (issued September 28, 2015).
[13] DR 14 Attachment 163
[14] DR 788 Attachment 1
[15] http://www.lipower.org/profile/10192015-DPS%20Recommendation.pdf

public power utility peer group. In response, LIPA adopted a five-year plan to improve ratings to A2/A/A.[16]

- **Reduce Borrowings to No More than 60-64 Percent of Capital Spending** – LIPA's debt ratio (defined as debt as a percentage of the net physical assets of the electric system plus working capital) is higher than the average utility. At the time LIPA adopted its new financial policy its debt ratio was 137 percent; whereas a ratio of 55 to 65 percent is typical for large public power utilities. LIPA's higher-than-average debt ratio is attributable to the debt incurred to acquire the Long Island Lighting Company (LILCO) electric system in 1998. In order to reduce the debt ratio over time, LIPA plans to reduce borrowings in each year to no more than 60 to 64 percent of capital spending, with the balance funded by cash flow from operations.[17]

- **Increasing Fixed Obligation Coverage Targets** – The coverage ratio is a measure of LIPA's ability to meet its fixed-charge obligations (debt service, interest, capitalized lease payments). To achieve the goals of improved credit ratings and reduced borrowing costs over five years, LIPA adopted fixed obligation coverage targets that increase each year from 1.2x in 2016 to 1.45x in 2019.[18]

Utility Debt Securitization Authority

The LIPA Reform Act's Securitization Law created the Utility Debt Securitization Authority (UDSA) in 2013 (Part B of Chapter 173, Laws of New York State). The UDSA has no commercial operations, and its sole mission is to authorize, issue and sell restructuring bonds, and to pay the financing costs, interest and principal on these bonds.[19] The proceeds from these bond sales are used to pay off outstanding LIPA bonds, which have much higher interest rates. UDSA debt is rated "AAA" by the major rating agencies, and results in a lower cost of funds than the lower-rated LIPA debt. UDSA's credit standing is based entirely on the agreement that it is paid from revenues of LIPA before any expense. It is not affected in any way by LIPA's credit standing, even including bankruptcy. The UDSA sold $2.0 billion of bonds in 2013. In 2015, the securitization law was amended to permit the UDSA to refinance up to $4.5 billion of LIPA bonds.

The Securitization Law authorizes:

- LIPA's Board to adopt restructuring cost financing orders which approve the "imposition and collection of transition charges, and the financing of approved restructuring costs and upfront financing costs through the sale of restructuring property and the issuance of restructuring bonds."[20] Each financing order creates a

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[16] DR 14 Attachment 163, pp. 4 and 57

[17] DR 14 Attachment 163, p 57

[18] DR 14 Attachment 163, p.5 and CFO Report to the Board of Trustees on Debt and Access to Credit Markets, March 20 2017

[19] http://www.lipower.org/UDSA/docs/MissionStatement.pdf

[20] The LIPA Reform Act, p.21

separate Restructuring Property, which is the right to collect from customers a non-by-passable charge necessary to pay the bonds and other ongoing financing costs.[21]

- LIPA to sell the restructuring property (i.e., the right to collect the non-by-passable charge) to the UDSA, which purchases the restructuring property with proceeds from the sale of the UDSA bonds.

- LIPA to use the sale proceeds from UDSA to pay off a portion of its outstanding debt.[22] Because the interest rate on UDSA bonds is lower than the rate on LIPA bonds, the combined effect is a lower cost of debt.

LIPA's Board adopted Financing Order No. 1 on October 3, 2013, and Financing Orders No. 2, No. 3 and No. 4, on June 26, 2015, which allowed the UDSA to issue Restructuring Bonds during 2015 and 2016.[23] The Board adopted Financing Order No. 5 on September 29, 2017. As of November 21, 2017, the UDSA had issued the entire $4.5 billion of authorized debt.

A schedule of LIPA and UDSA outstanding debt as of December 31, 2016, is shown in

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[21] http://www.lipower.org/pdfs/company/papers/board/07262017/2.2%20UDSA%20Financing%20Order%205.pdf

[22] UDSA Financing Order No. 5

[23] DR 123 Attachment UDSA Financing Orders July 2015.

Exhibit VI-2.

Exhibit VI-2
LIPA Outstanding Debt as of December 31, 2016 [Note 1]
(Dollars in Thousands)

	Beginning Balance	Accretion/ Additions	Maturities	Refundings	Ending Balance
LIPA Debt					
Electric System General Revenue Bonds					
(a) Series 1998A	$119,711	$6,359	$12,970		$113,100
(a) Series 2000A	348,279	19,613	33,525		334,367
Series 2003C	36,645				36,645
Series 2006A	499,200		40,625	458,575	
Series 2006D	55,360			55,360	
Series 2006E	310,240			310,240	
Series 2006F	239,050		27,360	183,155	28,535
Series 2008A	246,310			246,310	
Series 2008B	51,000			35,940	15,060
Series 2009A	222,610		2,770	28,170	191,670
Series 2010B	210,000				210,000
Series 2011A	234,225			12,590	221,635
Series 2012A	250,000				250,000
Series 2012B	188,715		9,680		179,035
Series 2012C	175,000			175,000	
Series 2014A	413,070				413,070
Series 2014B	164,950				164,950
Series 2014C	150,000				150,000
Series 2015A1	51,000				51,000
Series 2015A2	149,000				149,000
Series 2015B	117,230				117,230
Series 2015C	149,000				149,000
(b) Series 2015GR1-3 CP	50,000	170,625		65,000	155,625
Series 2016A		175,000			175,000
Series 2016B		407,675			407,675
Subtotal	**$4,430,595**	**$779,272**	**$126,930**	**$1,570,340**	**$3,512,597**
Electric system subordinate revenue bonds					
(b) Series 2014 CP 1AB	200,000			50,000	150,000
(b) Series 2014 CP 2AB	100,000				100,000
Subtotal	**$300,000**			**$50,000**	**$250,000**
UDSA Restructuring bonds					
Series 2013T	482,934				
Series 2013TE	1,434,390		60,000		1,374,390
Series 2015TE	1,002,115				1,002,115
Series 2016A		636,770			636,770
Series 2016B		469,320			469,320
Subtotal	**$2,919,439**	**$1,106,090**	**$60,000**	**$-**	**$3,965,529**
Total					
Subtotal - bonds and notes	**$7,650,034**	**$1,885,362**	**$186,930**	**$1,620,340**	**$7,728,126**
Plus: Net unamortized premiums	370,729	302,732	49,363		624,098
Total bonds, notes and premiums	**$8,020,763**	**$2,188,094**	**$236,293**	**$1,620,340**	**$8,352,224**

Note 1: 2017 data had not been available as of 3/6/18 (DR 964)

(a) Capital appreciation bonds

(b) Short term debt

Source: http://www.lipower.org/pdfs/company/trans/2016/LIPA%20Debt%20Outstanding%20YE%202016.pdf

B. APPLICATION OF INDUSTRY STANDARDS TO MANAGE DEBT

Evaluative Criteria

- Does LIPA have appropriate debt management and debt retirement plans?
- Does LIPA use industry benchmarking data to evaluate its debt costs?
- Does LIPA employ a fair and reasonable process for selecting underwriters that considers experience and marketing/distribution capabilities and the ability to obtain a high price/low interest cost for bonds sold?
- Are debt cost analyses appropriate and effective?
- Does LIPA monitor interest rates and other financial factors in the management of its debt costs?
- Has LIPA refinanced its debt to minimize costs?
- Are LIPA's long-term financing and debt retirement plans reasonable in light of system requirements and rate considerations?

Findings and Conclusions

1. LIPA's financial and debt management policies are appropriate and consider system requirements and rate effects.

- In 2015. LIPA's Board of Trustees approved a financial policy that guides LIPA's management of debt by using fixed obligation coverage and establishing sound financial planning metrics including.[24]

    - Achieving fixed obligation coverage of 1.20x in 2016 and increasing to 1.45x in 2019 and beyond.
    - Funding no more than 64 percent of capital expenditures with debt.
    - Maintaining cash on hand and available credit of at least 120 days of operating expenses.25

- This approach is often referred to as the Public Power Model.[26]

    - The Public Power Model calculates revenue requirements by adopting the perspective of the major rating agencies who determine, to a great extent, LIPA's access to financial resources (debt and credit) and the cost that LIPA pays for those financial resources (interest rates).[27]
    - The Public Power Model presumes that public power utilities like LIPA need to recover all of their operating costs, all of their debt service costs, and a level of fixed obligation coverage commensurate with their bond rating (which is also determined by other related factors).[28]

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[24] DR 14 Attachment 163 CFO report to the Board of Trustees March 29, 2017

[25] DR 14 Attachment 163

[26] http://www.lipower.org/pdfs/company/papers/board/committees/111714-fa-policies.pdf

[27] DR 145

[28] DR 145

  - The Public Power Model replaced a $75 million net income target that LIPA had previously used. In December 2005 the Board adopted a fiscal practice in connection with the 2006 Operating Budget to budget revenues and expenses to achieve $75 million of net income in each calendar year.[29]

- LIPA issues debt to fund its capital program (As discussed in Chapter V, approximately 75 percent of LIPA/PSEG LI's capital expenditures are for the T&D system; the remaining 25 percent are for LIPA's capital expenditures – 9 percent; PSEG LI IT – 7 percent; fleet – 5 percent; customer service – 2 percent; and facilities – 1 percent).[30] The current policy limits new borrowing to no more than 60 to 64 percent of capital spending and sets rates to achieve improved coverage ratios of obligations on its debt. Limiting new borrowing to no more than 60 to 64 percent of capital spending will improve LIPA's debt to total assets ratio from its level of 137 percent in December 2015.[31] As of December 2017, the projected debt to asset ratio for 2019 was 100.4 percent.[32]

- As shown in **Exhibit VI-3**, current targets for the percentage of capital funded by new debt are less aggressive than the targets initially adopted in the 2016 Operating and Capital Budgets as presented to the Board.

  - The 2016 budget projected that 50 percent of capital spending would be funded by debt in 2018; in contrast, the proposed 2018 budget has as less ambitious target of 57 percent which uses more debt and less internal funds to fund anticipated spending.
  - The 2016 Budget amounts reflect the DPS' Three Year Rate Recommendation which excluded certain capital projects planned for 2017 and 2018 with the explicit understanding that those projects could be added back as needed. These capital projects were included in the 2018 capital budget and impact the percentage of capital spending to be funded by new debt.

Exhibit VI-3
Percentage of Capital Spending Forecast to be Funded by New Debt

	2016	2017	2018
All Capital Spending			
2016 Budget	63%	46%	50%
2018 Budget		55%	57%

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[29] DR 14 Attachment 163 December 16, 2015 Board Approval to Implement of the Department of Public Service Rate, p.4

[30] DR 781 Attachment 1

[31] DR 14 Attachment 163 December 16, 2015 Board Approval to Implement of the Department of Public Service Rate, p.57

[32] LIPA 2018 Budget. http://www.lipower.org/pdfs/company/papers/LIPA_2018Budget%201-18%20web%20approved.pdf

	2016	2017	2018
Excluding FEMA[33]			
2016 Budget	83%	72%	66%
2018 Budget		73%	72%

Source: DR 14 Attachment 163, Appendix B, p. 9; Proposed 2018 Budget November 14, 2017.

- According to LIPA, its new financial policy charts a path to achieve A2/A/A bond ratings within 5 years.[34]

- To achieve the goals of improved credit ratings and reduced borrowings over five years, LIPA adopted annual fixed obligation coverage ratio targets.

  - Coverage is the amount of revenues in excess of operating expense plus debt service that LIPA recovers from customers each year.[35]
  - The amount of coverage represents a margin of safety for bondholders, and the rating agencies assign a higher rating for higher achieved coverage ratios, resulting in lower interest rates.[36]
  - Coverage is not owed to any bond holder or financial institution and is retained by Authority until used for other purposes for the benefit of the Authority's rate payers.[37]
  - In LIPA's financial planning, establishing sufficient coverage is the mechanism that enables LIPA to achieve its financial target of borrowing no more than 64 percent of the spending on capital improvements; internally generated funds are able to provide more than 36 percent of the need for new capital each year. This level of coverage reassures bond holders and rating agencies that LIPA is worthy of better credit ratings, thereby reducing the cost of borrowing.[38]

- LIPA's coverage targets, with and without UDSA bonds, are shown in **Exhibit VI-4**. **(**The financial policy specifies a fixed obligation coverage target on combined LIPA and UDSA debt, because one of the three major rating agencies (Moody's) prefers this combined metric.).[39] A 1.4 target coverage ratio means that LIPA includes 1.4 times the fixed obligation amount in its base rate revenue requirements for the year, so that its revenue is able to cover 140 percent of its fixed obligations.

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[33] FEMA related storm damages are discussed in Chapter V Budgeting and Financial Reporting
[34] CFO report to the Board of Trustees March 29, 2017 and DR 126 Attachment Trustee FA CFO Presentation
[35] DR 145
[36] DR 145
[37] DR 145
[38] DR 145
[39] DR 145

Exhibit VI- 4
Minimum Fixed Obligation Coverage Ratios in LIPA's Financial Policy adopted December 2015

Fixed Obligations	2016	2017	2018	2019
Authority Debt + Capitalized Leases [Note 1]	1.20x	1.30x	1.40x	1.45x
Authority Debt + UDSA Debt + Capitalized Leases	1.15x	1.20x	1.25x	1.25x

Note 1: Long-Term Purchase Power Agreements (PPAs) are treated as capitalized leases. Both the accounting profession and rating agencies view capitalized leases as the financial equivalent of debt (DR 145)
Source: DR 14 Attachment 163, 12/16/2015 Board Approval Package.

- Implementation of the Public Power Model for setting rates and criteria for new borrowing relative to capital spending immediately resulted in improved outlook by the rating agencies.
  - LIPA's 2015 Annual Report, issued March 31, 2016, states, "[a]ll three of the major credit rating agencies have recently recognized LIPA's progress in adopting sound fiscal practices by changing our bond rating outlooks from "negative" to "stable."[40]
  - By September 2016, LIPA's credit ratings were A3(stable)/A-(stable)/A-(stable) (Moody's/S&P/Fitch).[41]

2. **Although LIPA has no plans for the early retirement of debt, its ratio of debt to total assets will improve through the implementation of its debt management plan.**

- LIPA does not plan to retire (repay with cash) its debt, except in accordance with the terms of the bonds, and through refinancing with UDSA funds.[42]

- By limiting new borrowing to no more than 60 to 64 percent of capital spending, the ratio of debt to total assets will decrease, in spite of the fact that LIPA's total amount of debt will increase over time.

- As existing debt matures or is refinanced, the total amount of debt outstanding is expected to increase from current levels over time.
  - "Refundings" or the refinancing of outstanding bonds are commonly used to achieve savings, remove or change bond covenants, restructure debt, or refinance bonds that are enhanced by expiring bank liquidity facilities or that have similar mandatory refinancing features.
  - In accordance with LIPA's debt management policy, most refinancing will be undertaken to achieve debt service savings (i.e. replacing current debt with bonds that have lower principal and interest payments through maturity as

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[40] LIPA 2015 Annual Report, p. XII
[41] http://www.lipower.org/financials.html
[42] DR 14 Attachment 163

measured on a present value basis). As a general policy, LIPA does not extend the average weighted life (i.e., average maturity) of bonds as a result of refinancing.[43]

3. UDSA financing has enabled LIPA to greatly reduce its cost of debt.

- LIPA has refinanced portions of its debt to decrease its costs. The largest component of LIPA's debt refinancing has been the sale of UDSA bonds which have a much lower cost of interest than LIPA debt. The proceeds from the UDSA bond sales are used to pay off, that is to retire, LIPA bonds.

- As of November 21, 2017, the UDSA had issued the entire $4.5 billion of authorized debt. **Exhibit VI-5** is a summary of the results of each UDSA Financing Order.

Exhibit VI-5
UDSA Financing Orders

Order/ Issue Date	Restructuring Bonds	Amount (Millions)	NPV Savings (Millions)	Average Life (Years)	All-in-Cost [Note 1]
1 12/18/2013	2013 Restructuring Bonds	$2,022	$132	14	4.22%
2 10/27/2015	2015 Restructuring Bonds	$1,002	$128	16	3.40%.
3 4/7/2016	2016A Restructuring Bonds	$636	$115	12	2.70%.
4 9/8/2016	2016B Restructuring Bonds	$469	$71	7	2.01%
5 11/21/2017	2017 Restructuring Bonds	$369	$45	17	3.45%
Total		**$4,500**	**$491**		

Note 1: All-in-Cost is a measurement of the total cost of a bond financing, expressed as a discount rate calculated using the present value of all debt payments on the issue and the total proceeds of the issue.
Source: LIPA CFO Report December Board of Trustees, December 14, 2017.

- As shown in **Exhibit IV-5**, LIPA realized $491 million savings from UDSA refinancing on a net present value basis.

4. LIPA has appropriately taken actions in addition to the UDSA refinancing to reduce its cost of debt.

- In addition to the debt cost reductions obtained from UDSA bonds, LIPA has engaged in other restructuring activities that have reduced its cost of debt. Some of these actions include:
  - Issued General Revenue Bonds 2016A to refinance $175 million letter of credit-backed Variable Rate Demand Bonds. Produced annual savings of 0.7 percent or $5.6 million over the first five years.

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[43] DR 132

  - Refinanced $65 million of General Revenue fixed-rate bonds. Produced $8.4 million present value savings.
  - Renewed bank agreements to lock in lower costs, including:
    - Extend one-year letter of credit with TD Bank
    - Enter new letter of credit with U.S. Bancorp
    - Extend $337.5 million revolving line of credit with TD Bank for one year.[44]

5. LIPA appropriately and effectively manages its debt costs using information on interest rates and other financial factors it obtains from its underwriters. LIPA has a sound process to select underwriters.

- Underwriters are an important part of LIPA's debt issuance team.
  - The underwriter chosen for a particular transaction works with LIPA to structure the transaction, assist in the rating agency presentations, develop a marketing plan, draft and develop an investor presentation, and ultimately price the bonds or notes and place them with investors.
  - After the transaction is priced, the underwriter provides the required cash flow analysis for all of the necessary approvals.[45]

- LIPA selects underwriters that provide both services related to debt issuance and provide industry data and benchmarking analyses. The selected underwriters serve for a period of five years.[46]

- LIPA uses an open, competitive process to identify and select a pool of underwriters.
  - LIPA's Procurement department, with assistance from LIPA's CFO and its Financial Advisor, prepares the RFP.
  - A selection committee consisting of LIPA staff and its Financial Advisor evaluates the proposals and makes its recommendation to the LIPA Board of Trustees (BOT) or the UDSA Board for final approval.[47]

- NorthStar reviewed the underwriter selection criteria and found them to be appropriate. LIPA considers the experience and marketing/distribution capabilities of the underwriters with public power financings as well as their success in obtaining appropriate price/interest rates for the bonds sold.[48] As part of the proposal process, the underwriters provide suggested market approaches for the next five years.[49]

- LIPA relies on data from its underwriters to analyze its debt costs compared to industry standards**.** One of LIPA's criteria for selecting underwriters is that the

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[44] DR 126 Attachment Trustee
[45] DR 124
[46] IR 82 & 83
[47] DR 128, 129
[48] DR 128, 129
[49] IR 82 and 83

underwriters have significant amounts of currently maintained debt costs for benchmarking data as well as effective analytical tools.[50]

C. RECEIPT OF NECESSARY APPROVAL FOR DEBT MANAGEMENT

Evaluative Criteria

- Is documentation related to the debt issuance review and approval process complete and thorough?
- Does LIPA comply with applicable debt issuance requirements and are filings/ documentation complete?
- Has LIPA responded appropriately to the Finance Committee's recommendations with respect to its debt issuance proposals?

Findings and Conclusions

6. LIPA has complied with debt issuance requirements and has complete and thorough documentation related to the review and approval process.

- The issuance of LIPA debt requires three approvals:

  - **LIPA Board of Trustees**– All issuance of debt by LIPA requires authorization by the Board of Trustees. LIPA's By-Laws require that the Finance and Audit Committee make recommendations for debt issuance. In general, a supplement resolution to either the Authority's General Bond Resolution or Subordinated Bond Resolution will be recommended and will describe the proposed debt and its purposes. The Board also authorizes any necessary implementing agreements.
  - **Public Authorities Control Board (PACB)** – Once the Trustees have adopted a resolution authorizing the issuance of debt, LIPA is required by the LIPA Act and other provisions of the Public Authorities Law to obtain the approval of the New York State PACB.
  - **Office of State Comptroller (OSC**) – Public Authorities Law, Section 1020-k(4) requires that LIPA obtain OSC approval before issuing debt. When considering whether to approve a debt issuance, OSC reviews the terms and conditions of the sale, including all costs of issuance paid or to be paid directly or indirectly by the issuer. The OSC has specific guidelines and forms.[51]

- There are also three approvals required for the issuance of UDSA debt:

  - **LIPA Board of Trustees –** Part B of the LIPA Reform Act authorizes LIPA to adopt restructuring cost financing orders. If bonds are to be issued by the UDSA, the LIPA Trustees will adopt a Financing Order permitting such issuance and any

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[50] DR 128, 129

[51] DR 134

other required implementing documents.[52] The LIPA Reform Act requires that a financing order include, among other things, a finding by the Authority that the proposed issuance of securitized bonds to refinance the selected target debt "is expected to result in savings to [LIPA's] customers on a net present value basis".[53]

- **PACB –** Part B of the LIPA Reform Act provides that the PACB must approve or disapprove of any LIPA restructuring cost financing orders.[54] The LIPA Reform Act provides that if PACB does not act to approve or disapprove a financing order within 30 days of its submission, it is deemed approved.[55]
- **UDSA Board of Trustees** – Following the execution of LIPA financing order and PACB approval, the UDSA Trustees authorize the UDSA's issuance of restructuring bonds.[56]
- While the Comptroller's approval is necessary for issuance of LIPA debt, it is not required for issuance of UDSA debt.[57]

- NorthStar reviewed the review and approval documentation for selected UDSA and LIPA bond issuances and found adequate support for the requisite approvals.[58]

- Documentation of filings is also reviewed by experienced external bond counsel for accuracy and completeness.

7. NorthStar's review of Finance & Audit (F&A) Committee meeting minutes identified no instances in which the Committee made a recommendation to LIPA regarding its debt proposal. There are therefore no instances in which LIPA did not respond appropriately to the F&A recommendations.

- The F&A Committee of LIPA's Board of Trustees reviews proposed debt issuances and restructuring finance orders prior to recommending them to the Board.[59]

- LIPA's CFO meets with the F&A Committee and explains the current plan of finance, timing of any new issuances and expected ratings. If the F&A Committee has questions or concerns, they are responded to by LIPA's CFO.[60]

- NorthStar's review of F&A Committee meeting minutes 2014 through September 2017 identified no instances in which the Committee made a recommendation to

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[52] DR 134

[53] DR 16 Attachment 062615 finance minutes

[54] DR 774 Attachment 4

[55] DR 16 Attachment 062615 finance minutes

[56] DR 14 Attachment 163

[57] IR 82 & 83

[58] DR 775 all attachments.

[59] http://www.lipower.org/pdfs/company/papers/board/committees/Committee_Charters_2017.pdf

[60] DR 434

LIPA regarding its debt proposal.[61] There were no instances in which LIPA staff sought approval to issue debt that was not already approved in the annual budget.[62]

D. AUDIT OF DEBT MANAGEMENT PRACTICES

Evaluative Criteria

- Does LIPA have an appropriate policy for the internal audit of its debt management?
- Are audits well documented?
- Does LIPA take appropriate action in response to its internal audit organization reviews?
- Does LIPA effectively manage its credit rating agency relationships and respond to credit rating agencies in an appropriate manner?

Findings and Conclusions

8. LIPA's policy to conduct one or more internal audits of debt management each year is appropriate, and its internal audits of debt management are adequately documented.

- LIPA's Internal Audit policy to perform at least one audit of debt management each year, which should insure appropriate coverage of potential risks.[63]

- During the four years, 2014-2017, Internal Audit conducted three audits of LIPA's debt management, and one audit of UDSA's debt management.[64]

- LIPA provided extensive documentation, including work papers, for its internal audits of Debt Management.[65]

- NorthStar reviewed the documentation for all audits of debt management and found it to be comprehensive and appropriate.

9. LIPA proactively manages its relations with major credit rating agencies.

- LIPA's CFO has frequent interactions with rating agencies through emails, calls and meetings.[66]

- After determining the key factors rating agencies consider in evaluating credit of public power agencies, LIPA developed and adopted a financial policy designed to achieve specific improvements in key financial measures.[67]

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[61] DR 14
[62] LIPA/PSEG LI Fact Verification
[63] DR 33 Attachment LIPA Internal Audit Policies and Procedures
[64] DR 138, DR 35 (2014 #9, 2015 #11, 2017 #12),
[65] DR 687
[66] DR 688

- LIPA has informed the rating agencies of its policy and keeps them informed of its progress in achieving each improvement.[68]

E. EFFECTIVENESS OF RISK MANAGEMENT TECHNIQUES

Evaluative Criteria

- Does LIPA have an appropriate debt management policy, statement and strategy?
- Does LIPA have appropriate processes for monitoring interest rates and other financial factors relative to its risk management techniques?
- Are LIPA's interest rate swap policies and procedures appropriate?
- Are debt financing risks included in the Enterprise Risk Management (ERM) process?

Findings and Conclusions

10. LIPA has appropriate processes for monitoring interest rates and other financial factors relative to its risk management techniques.

- LIPA's CFO receives and reviews routine reports regarding municipal market financial factors from its financial advisors, including the following:
  - Daily market updates regarding certain interest rates and ratios, as well as graphs and charts depicting current and historical data.
  - Weekly updates showing the "week in review" and "week ahead" data including the volume in the municipal market, current and historical credit spreads and Municipal Market Data yields.[69]

- LIPA's finance staff maintains an Excel spreadsheet containing the details of its general revenue and subordinated revenue commercial paper programs. The spreadsheet compiles nine months of historical commercial paper data with the dates of commercial paper rolls, principal amount and interest rates. Additionally, the file sets forth the letter of credit terms for each of the commercial paper programs.[70]

- LIPA's annual budget includes interest costs. On an ongoing basis, actual interest costs are compared with budgeted amounts. Quarterly reports which include interest expenses and debt activities are provided to the Board of Trustees of both LIPA and UDSA. [71]

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[67] DR 14
[68] DR 137, 688
[69] DR 131
[70] DR 131
[71] DR 131

11. LIPA's interest rate swap policies and procedures are appropriate.

- Interest rate swaps are used to mitigate interest rate exposures on LIPA's debt portfolio. LIPA does not enter interest rate exchanges for speculative purposes.[72]

- On May 18, 2016 the Board adopted "Comprehensive Guidelines for the Use of Interest Rate Exchange Agreements." These guidelines are available on LIPA's website.[73]

- Key provisions of the Interest Rate Exchange Agreement Guidelines include:

  - Agreement terms cannot exceed the lesser of the final maturity of LIPA's then-outstanding obligations or the term of any approved LIPA financial plan.
  - Counterparties must have credit ratings from at least two nationally recognized rating agencies that are within the three highest grade categories, or the payment obligations of the counterparty shall be unconditionally guaranteed by an entity with such credit ratings.
  - The mark-to-market value of the swap does not require collateralization unless the counterparty is downgraded by any nationally recognized ratings agency below the three highest grade categories.
  - Each agreement may include a provision that allows LIPA to exercise a right to terminate the agreement if the counterparty's, or the counterparty's guarantor's rating or ratings are lowered to or below a level specified in the Agreement.
  - LIPA will seek to avoid excessive concentrations of exposure to a single counterparty or guarantor by diversifying its counterparty credit exposure over time.
  - LIPA pre-approves counterparties pursuant to a Request for Qualifications (RFQ).[74]

- LIPA provides quarterly reports to the Board on its interest rate exchange agreements. Information provided includes:

  - Interest payments received or paid
  - Accrued interest payable or receivable on the swap
  - Swap strategies and management techniques
  - Status of interest rate exposure, net of the effects of swap agreements
  - Status of individual agreements in effect, including notional amount, rates, terms, bases employed and the rating of counterparties/insurers
  - The credit terms within International Swaps and Derivatives Association (ISDA) documentation, such as ratings-based triggers for termination events and collateral posting terms and requirements

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[72] DR 139

[73] DR 139

[74] DR 139

  - The mark-to-market evaluations of net credit exposures by individual counterparties, and collateralization that has been provided
  - The summary of the terms and conditions of agreements executed since the previous report
  - The status of the Qualified Independent Representatives under the Dodd-Frank Act.[75]

- A subcontractor to LIPA's external financial advisor provides services associated with LIPA's swap portfolio.[76]

  - Review of the quarterly swap report
  - Quarterly market valuations of LIPA's outstanding swaps
  - Daily market reports
  - Interactions with LIPA's swap counterparties on LIPA's behalf.[77]

12. LIPA's Enterprise Risk Management Committee provides appropriate oversight of LIPA's interest exchange program.

- The Enterprise Risk Management Committee (ERMC) is discussed in **Chapter IV – Enterprise Risk Management**. ERMC members include the Chief Financial Officer (as ERMC Chair) and at least two other LIPA staff members, one of which must be from LIPA's senior management.[78]

- LIPA may enter an interest swap agreement only if the ERMC determines that the agreement is reasonably expected to provide one or more of more of the following objectives:

  - Reduce exposure to changes in interest rates on a particular financial transaction, or in the context of the management of interest rate risk derived from an asset/liability imbalance (imbalance between interest earned and interest paid).
  - Result in a lower net cost of borrowing with respect to the related obligations.
  - Manage financial exposure with respect to its current financial condition.[79]

- The ERMC also considers the risk exposures associated with counterparty risk, termination risk, basis risk, tax-event or tax-basis risk, mismatched amortization risk (if any), and rollover risk.[80]

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[75] DR 139
[76] DR 690
[77] DR 690
[78] DR 50 Attachment 2
[79] DR 139
[80] DR 139

F. EFFECTIVENESS OF LIPA'S DEBT MANAGEMENT STRATEGIES IN MEETING ITS DEBT OBLIGATIONS

Evaluative Criteria

- Does LIPA have appropriate policies, analyses and plans that address its debt management strategies relative to meeting its debt obligations?
- Does LIPA appropriately respond to meetings and reports from credit rating agencies with regard to LIPA meeting its debt obligations?
- Does LIPA consider assessments and recommendations from its regulatory bodies in its ratemaking model?
- Do major capital projects have specific funding sources and are they documented?
- Is the effect on customer rates given appropriate consideration in debt planning?

Findings and Conclusions

13. LIPA does not use traditional project financing for its capital projects.

- LIPA does not do project-specific financing in the traditional sense of borrowing against a project's projected cash flow for repayment, with the project's assets, rights and interests held as security or collateral.[81]

- LIPA issues general revenue bonds and notes to finance the overall capital program. There are no pledged assets as in project finance. There is a general revenue pledge securing the bonds.[82]

14. LIPA considers assessments and recommendations from its regulatory bodies in its rate setting process in accordance with the LIPA Reform Act.

- The LIPA Reform Act requires the Department of Public Service (DPS) to establish an evidentiary process for LIPA initial Three-Year Rate Plan (2016 – 2018) and any subsequent proposal that would increase base rates by more than 2.5% percent of total revenues.[83]

- The DPS' role in the rate making process is to organize and hold the evidentiary process, participate in the evidentiary process as it deems appropriate and advisable, and provide to LIPA's Board of Trustees at the conclusion of the process a recommendation on the rates at the lowest level to provide safe and adequate service consistent with sound fiscal operating practices.[84]

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[81] DR 691
[82] DR 691
[83] DR 145
[84] DR 145 and the LIPA Reform Act, p. 3

- LIPA implements the recommendation of DPS unless, in the opinion of the Trustees, it is inconsistent with the authority's sound fiscal operating practices, any existing contractual or operating obligations, or the provision of safe and adequate service.[85]

15. LIPA's debt planning process gives appropriate consideration to the impact of debt on customer rates. Implementation of the Public Power Model and Three Year Rate Plan entails the explicit determination of the impact of financing decisions on revenue requirements.

- LIPA's base rates include components for debt service (including new capital debt service), floating rate notes (including interest and line of credit/remarketing fees), interest rate swaps, interest earnings, and savings from UDSA refunding.[86]

- The Three-Year Rate Plan includes annual adjustments to base rates based on staged updates and Delivery Service Adjustments (DSAs), which were performed each year in October/November from 2015 to 2017. The adjustments are reflected in next years' customer bills. The three staged updates are forward-looking (i.e., the November 2017 update looks at costs to be incurred in 2018); while the DSA reconciliations are backward-looking (i.e., the November 2017 DSA calculation trues up the projected and actual costs for the previous year ending September 30).[87]

- As shown in **Exhibit VI-6**, LIPA and UDSA debt costs are included in the staged update.

Exhibit VI-6
Overview of Staged Updates and DSA Components
(Debt-related items are highlighted in yellow)

Rate Case Adjustment	Items Covered
Staged Update	• Planned Capital Expenditure financing for next year • Planned UDSA refinancing for next year • Cost Benefit Analysis and associated costs for changes in the level of benefits and payroll related overhead costs (e.g., payroll taxes) • Current interest rates • Power Supply Agreement (PSA) pension/Other post-employment benefits (OPEB) settlement • PSA property tax settlement • Transmission and Distribution (T&D) property payments in lieu of taxes (PILOTs) actual expense times known percentage increase over previous year • Other legal or regulatory mandates

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[85] DR 145 and the LIPA Reform Act, p, 10
[86] DR 145
[87] 152 2015009-28 Final Department Rate Recommendation Appendix II, p.1.
http://www.lipower.org/newscenter/docs/Department%20Rate%20Recommendation.pdf

Rate Case Adjustment	Items Covered
DSA	• True-up of the cost of debt service, other interest earnings and expense for the previous 12-month period ending September 30. • Storm Cost Reserve (including storm preparation) • PSA/Nine Mile Point (NMP) Expense

Source: Final Department Rate Recommendation Appendix II at http://www.lipower.org/newscenter /docs/Department%20Rate%20Recommendation.pdf

- LIPA uses a complex Excel model to determine the staged update amounts to include in next year's rates. The staged update model includes the debt service cost calculations listed in **Exhibit VI-7**.

Exhibit VI-7

Stage Update Debt Component Calculations

Debt Component	Projected Cost Calculation
LIPA Debt Service	Outstanding Fixed and Variable Rates Debt Service + Commercial Paper - LIPA Debt Service Defeased - LIPA Service Refunded by UDSA Transactions LIPA Debt Service
UDSA Debt Service	UDSA Debt Service Costs
Fixed Coverage Amounts	LIPA Debt Service Replaced by UDSA X Fixed Coverage Ratio as specified in financial policy + LIPA Debt Service + Capitalized Lease Amounts [Note 1] X Fixed Coverage Ratio Fixed Coverage Amount
Interest Expense	Line of Credit and Remarketing + Interest Rate Swap Fees + Bond Fees and Deposits Interest Expense

Note 1: Capitalized leases are obligations of LIPA, usually in the form of Power Purchase Agreements (PPAs), which represent long term obligations of LIPA.[88]

Source: NorthStar Analysis of DR 145

- The DSA trues up the projected variable rate debt and interest expenses with the actual costs incurred in the 12-month period ending September 30.

G. COMPLIANCE WITH DEBT COVENANTS

Evaluative Criteria

- Does LIPA have appropriate policies and procedures for ensuring compliance with debt covenants?
- Does LIPA appropriately manage debt covenant defaults?
- Does the Board of Trustees effectively monitor LIPA's debt covenant compliance?

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[88] 12/16/2015 Board Approval Package

- Does LIPA have appropriate processes for ongoing review of its debt covenant requirements?
- Has LIPA been effective in modifying its debt covenant requirements to increase efficiencies, reduce costs and minimize risks?

Findings and Conclusions

16. LIPA's policies and procedures for ensuring compliance with debt covenants have improved. LIPA is currently implementing an automated approach to be fully aware of and compliant with all debt covenants.

- An Internal Audit review completed in July 23, 2015, determined that LIPA needed to improve debt covenant compliance by updating procedures and formalizing the process.

- Since the 2015 internal audit, LIPA contracted with a professional legal firm to develop written procedures for compliance. These procedures were detailed and required extensive effort.[89]

- In October 2017, LIPA issued a Request for Proposal (RFP) soliciting a contractor to develop a more automated approach to ensuring compliance with debt covenants.[90]

17. LIPA is not aware of any debt covenant defaults.[91]

18. The Board of Trustees appropriately monitors debt covenant compliance independently.

- The F&A committee has responsibility for overseeing, monitoring and making recommendations with respect to LIPA's debt management policies and procedures.[92]

- LIPA's Director of Internal Audit reports functionally to the Board's F&A Committee, and administratively to LIPA's Chief Executive Officer.[93] Internal Audit audits debt management every year.

- In 2015 Internal Audit performed an audit of "Debt Covenant Compliance and Post-Issuance Tax Compliance," and its 2017 audit of Debt Management included a review of LIPA's compliance with bond covenants.

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[89] DR 181

[90] http://www.lipower.org/proposals/docs/debtcovenantmanagementsystem/RFP-%20Debt%20Covenant%20Management%20System-10-3-Final.pdf

[91] DR 437

[92] DR 30 Attachment Board Committee Charters

[93] DR 30 Attachment Board Committee Charters

19. **LIPA conducted a review of some of its debt covenants to identify where improvements could be made and succeeded in modifying the covenants on debt from several institutions to use common language. This will result in reduced costs of administering covenant compliance.**

    - LIPA negotiated a modification of its debt covenant reqirements from several institutions within the past year. When establishing lines of credit with four banks, LIPA succeeded in "homogenizing" the covenants and in allowing proactive reporting on its website rather than individual paper reports thus streamlining the process for both LIPA and its banks.[94]

H. CASH RESERVE POLICY

Evaluative Criteria

- Is LIPA's cash reserve policy appropriate?
- Are reserve requirements evaluated on a routine, periodic basis and adjusted as appropriate?

Findings and Conclusions

20. **LIPA has an appropriate cash reserve policy that is consistent with policies that rating agencies favorably consider when evaluating public power authority credit.**

    - LIPA's policy is to maintain cash on hand and available credit equal to at least 120 days of forecasted operating expenses.[95] In accordance with the Board policy:

        - Days Cash on Hand measures LIPA's ability to sustain its operations if revenues are delayed, reduced or interrupted for any reason.
        - Days Cash on Hand is the ratio of the total cash and credit available divided by LIPA's average daily operating expenditures.
        - Available cash consists of cash reported on the balance sheet and includes both unrestricted cash and funds that are held in a restricted account dedicated to pre-funding PSEG Long Island's operating and capital expenditures, in accordance with the terms of the A&R OSA.
        - Available credit includes multiple sources such as commercial paper, letters and lines of credit, and general revenue notes.
        - Average daily expenditure is calculated by taking LIPA's annual approved budgeted revenues minus depreciation, amortization, and interest expense and dividing the net value by 365 days.[96]

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[94] IR 208

[95] DR 146

[96] DR 693

- The Controller and Chief Financial Officer report the Authority's liquidity position to the F&A Committee in the monthly financial report.[97]

- LIPA Treasury monitors operating cash to ensure sufficient cash is available to meet upcoming cash requirements. Information is tracked to ensure sufficient liquidity to meet obligations.

  - If the analysis projects a liquidity need, Treasury informs the Chief Executive Officer (CEO) and/or CFO.
  - The appropriate Finance Department designee reviews the credit facility capacity available to LIPA and determines the short-term financing that meets the needs requirement.
  - Depending on market conditions of the long-term debt market, it may be beneficial for LIPA to utilize short-term debt to fund long-term bonds in the interim.
  - A short-term debt schedule is prepared by the appropriate Finance designee monthly to note the purpose of drawing on LIPA's short-term financings.[98]

- LIPA established its current cash reserve policy as part of the Financial Plan adopted by the Board in December 2015.[99] As part of the Financial Plan, LIPA has a goal of achieving ratings of A2/A/A from the three rating agencies. One rating agency criterion is Financial Strength and Liquidity, including Cash-on-Hand.

  - Moody's bond rating criteria ascribes a value of 10 percent to Adjusted Days Liquidity on Hand.
  - Moody's Cash Reserve Rating Criteria is shown in **Exhibit VI-8**.

Exhibit VI-8
Moody's Cash Reserve Rating Criteria

Rating	Days Cash on Hand (3 Year Average)
Aaa	≥ 250
Aa	150 - 250
A	90 - 150
Baa	30 - 90
Ba	15 - 30
B	< 15

Source: DR 693 Attachment 1.

- The 120-day level was established because it is consistent with the midpoint of the "A" category rating which ranges from 90 days to 150 day's liquidity on hand.[100]

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[97] DR 146

[98] DR 125 Attachment Debt – Policies and Procedures

[99] DR 14 Attachment 163

[100] DR 463

21. **There is no need for LIPA to review its cash reserve requirements on a routine, periodic basis, as the liquidity requirements for an A-rated credit generally do not change and accordingly, LIPA has not done so.**

   - There have been no adjustments to the cash reserve policy since the Board established the 120-day reserve requirement in December 2015.[101]

   - LIPA has reviewed this policy twice since it was set. In September 2016, and again in March 2017, the Board adopted and amended the Debt and Access to the Credit Markets Policy.[102]

   - Since the liquidity requirements for an A-rated credit remain the same, the 120-day cash reserve policy remains appropriate.[103]

   - LIPA states that it will always review the cash reserve policy and any other self-imposed requirement for potential modifications in the future should conditions warrant a change in the policy.[104]

I. ACQUISITION ADJUSTMENT

An acquisition adjustment is the premium paid for acquiring a company for more than its tangible assets or book value. In May 1998, LIPA acquired LILCO and recorded a $4.1 billion Acquisition Adjustment which reflects the excess cost paid to acquire LILCO over the sum of the amounts assigned to all identified assets acquired and liabilities assumed.[105] Although the Acquisition Adjustment is sometimes referred to as the "Shoreham Acquisition" adjustment, there is no specific "Shoreham acquisition" which is distinct from LIPA's acquisition of LILCO's stock and assets.[106]

Evaluative Criteria

- Does LIPA have appropriate plans for the amortization of the Acquisition Adjustment and related debt, and does LIPA adequately manage and execute these plans?
- Is there adequate correspondence and other documentation between LIPA and its regulatory bodies as it amortizes the Acquisition Adjustment and retires the related debt?
- Has LIPA taken appropriate actions in response to any recommendations made by the regulatory bodies to which it is accountable, as it amortizes the Acquisition Adjustment and retires the related debt?

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[101] DR 693

[102] DR 693

[103] DR 693

[104] DR 693

[105] DR 147 Attachment Policies and Procedures and DR 428.

[106] The RFP for this audit refers to the "Shoreham Acquisition Adjustment", and a 2011 Brattle Group report refers to the "non-productive $2.6 billion Shoreham Acquisition asset." (http://www.lipower.org/pdfs/company/papers/strategic-brattle.pdf)

- Is the methodology used by LIPA to determine the Acquisition Adjustment and subsequent changes to the adjustment consistent with general accepted accounting principles, Trustee decisions and regulatory orders?

Findings and Conclusions

22. LIPA has no plans to specifically address the amortization of debt that related to the Acquisition Adjustment because LIPA has no debt that is specifically associated with the Acquisition Adjustment.

- In 1998, LIPA issued $6.73 billion in bonds to finance the acquisition of the transmission and distribution system of LILCO and to refinance portions of LILCO's outstanding debt, including costs related to the Shoreham Nuclear Power Project, which never became operational.[107]

- LIPA did not issue a specific series of debt that is associated with the Acquisition Adjustment.[108] LIPA had originally intended for debt approximately equal to the $4.0 billion Acquisition Adjustment to be retired by 2013 through a series of scheduled and optional debt repayments.[109] However, the anticipated optional debt payments were foregone by LIPA in order to subsidize customer fuel and purchased power costs, a practice which LIPA has since ceased, as well as to finance LIPA's capital expenditure program.[110]

- As previously shown in **Exhibit VI-2,** as of December 21, 2016, the Series 1998A General Revenue bonds had a balance of $113.1M. LIPA originally issued $3.5 billion of Series 1998A bonds as part of its financing the LILCO acquisition.[111] The Series 1998A bonds are the only bonds remaining that were issued in 1998.

23. LIPA has an appropriate plan for the amortization of the Acquisition Adjustment that reflects LIPA staff recommendation and Board's authorization, which are in accordance with the DPS Rate Recommendation.

- In 1998, LIPA amortized the Acquisition Adjustment over 35 years, through 2033, based on the weighted average useful life of the net assets acquired.[112]

- In 2015, LIPA's Board of Trustees approved an accounting adjustment which reduced the amortization period by approximately 6 years.

    - In 2014, the results of a depreciation study extended the estimated useful lives of certain LIPA electric assets, thus reducing depreciation rates. With the new

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[107] https://www.osc.state.ny.us/reports/pubauth/lipa_by_the_numbers_7_2015.pdf
[108] DR 147 Attachment Policies and Procedures
[109] http://www.lipower.org/pdfs/company/investor/2008B.pdf
[110] http://www.lipower.org/pdfs/company/papers/orgreview2010.pdf
[111] http://www.lipower.org/pdfs/company/investor/1998A.pdf
[112] DR 147

depreciation rates, LIPA's booked depreciation reserve, as of December 31, 2014, had a surplus of approximately $771 million excess accumulated reserves.

  - In accordance with a DPS Rate Plan Recommendation, the unamortized excess reserve balance was reclassified from the accumulated depreciation reserve and recorded as a regulatory liability. This regulatory liability was then netted against the Acquisition Adjustment to reduce the remaining unamortized balance of the Acquisition Adjustment by $718 million, as authorized by the Board of Trustees on December 16, 2015.[113]
  - This adjustment reduced the December 31, 2015 Acquisition Adjustment balance from $2.0 billion to $1.2 billion and reduced the amortizable life of the Acquisition Adjustment by approximately 6 years, so that the asset would be substantially fully amortized by December 31, 2026, rather than April 20, 2033.[114]

24. LIPA adequately manages and executes its plans for the amortization of the Acquisition Adjustment in accordance generally accepted accounting principles.

- LIPA has a documented financial procedure which requires the LIPA accounting staff to maintain an amortization schedule and post a monthly amortization journal entry.[115]

- LIPA's treatment of the Acquisition Adjustment is in accordance with the following accounting guidance:

  - Governmental Accounting Standards Board (GASB) No. 34, Basic Financial Statements and Management's Discussion and Analysis – for State and Local Governments, (paragraph 19)
  - GASB No. 62 Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 Financial Accounting Standards Board (FASB) and American Institute of Certified Public Accountants (AICPA) Pronouncements, Accounting and Financial Reporting for Intangible Assets.[116]

25. There is no on-going reporting by LIPA to its regulatory bodies regarding the amortization of the Acquisition Adjustment, however, this adjustment has no impact on revenue requirements and NorthStar sees no need for such periodic reporting.

- As pointed out in DPS Staff May 2015 rate case testimony, the Public Power Model does not include deprecation or amortizations as part of its revenue requirements because the costs are recovered through the debt service part of the calculation.[117]

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[113] LIPA annual report for 2016, p 26

[114] 12 /16/2015 Board Consideration of Approval to Implement the Department of Public Service Rate Recommendation and 2016 Operating and Capital Budgets as Required by the LIPA Reform Act

[115] DR 147 Attachment Policies and Procedures

[116] DR 147 Attachment Policies and Procedures

[117] DR 430, p. 30 of DPS staff testimony.

J. RECOMMENDATIONS

1. LIPA should build on its success in "homogenizing" groups of debt covenants to increase consistency among other debt instruments.

VII. LOAD FORECASTING AND SYSTEM PLANNING AND DISTRIBUTED SYSTEM PLATFORM (DSP) DEVELOPMENT

This chapter presents NorthStar's evaluation of PSEG LI's Load Forecasting and System Planning and DSP Development. It examines the models and inputs used to develop PSEG LI's load forecasts, and the accuracy of the forecasts. It also reviews PSEG LI's infrastructure planning, including the use of Reforming the Energy Vision (REV) initiatives.

A. BACKGROUND

The primary objective of load forecasting and system planning is to determine and satisfy load requirements while maintaining a high level of reliability at the lowest cost. Aging infrastructure, resource conservation, energy efficiency programs, and a decline in customers and sales due to economic slowdown and competitive alternative providers, increases the need for up-to-date, accurate and dynamic system planning.

Load Forecasting

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 and PSEG LI need to ensure that the 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, distributed energy resources (DERs), 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's energy and demand profile changed dramatically between 2007 and 2016. As shown in **Exhibit VII-1**, system sales have decreased four percent while peak demand has increased two percent over the past ten years. **Exhibit VII-2** provides sales by sector – residential and commercial.

Exhibit VII-1
Weather-Normalized LIPA Electric Sales

Year	Total Sales (GWh)	Normalized Sales (GWh)	System Peak (MW)	Normalized Peak (MW)
2007	20,108	20,188	5,247	5,239
2008	19,888	20,293	5,130	5,284
2009	19,379	19,862	5,034	5,208
2010	20,376	19,970	5,719	5,303
2011	20,248	20,147	5,783	5,269
2012	19,954	20,297	5,373	5,372
2013	19,931	19,835	5,653	5,385
2014	19,687	19,852	4,927	5,411
2015	19,926	19,557	5,134	5,372
2016	19,600	19,389	5,285	5,356
Percent Change in Sales and Peak Demand				
2007 to 2016		-3.9%		2.2%
2012 to 2016		-4.5%		-0.30%

Source: DR 162, 236, 650 and 959.

Exhibit VII-2
Residential and Commercial Sales

Year	Residential		Commercial	
	Actual	Normalized	Actual	Normalized
2007	9,555,338	9,635,443	10,100,007	10,099,695
2008	9,572,398	9,754,301	9,979,927	10,073,289
2009	9,275,344	9,614,654	9,643,092	9,786,818
2010	9,971,614	9,688,096	9,950,584	9,828,797
2011	9,848,965	9,755,303	9,818,456	9,810,484
2012	9,735,407	9,904,131	9,666,106	9,840,568
2013	9,536,152	9,479,495	9,800,324	9,760,923
2014	9,389,926	9,525,137	9,700,047	9,730,020
2015	9,611,160	9,365,560	9,730,214	9,606,866
2016	9,463,401	9,299,261	9,581,965	9,535,256
Percent Change in Sales				
2007-2016		-3.5%		-5.6%
2012-2016		-6.1%		-3.1%

Source: DR 236 and 959.

Use per customer has declined over the last ten years as shown in **Exhibit VII-3**. Traditionally, as the population increases, the number of customers increases, resulting in increased sales. This expected increase in LIPA sales has been offset by the impacts of Superstorm Sandy, an economic downturn in the early part of the past decade and gains in energy efficiency, resulting in almost flat sales between 2007 and 2014 in the residential sector. The past two years (2015-2016) has experienced an increase in number of customers and decreased sales. This resulted in decreased use-per-customer indicates a major change in customer end-uses.

Exhibit VII-3
Weather-Normalized Customer Sales

Year	Residential Customers	Annual Sales per Residential Customer (kWh)	Commercial Customers	Annual Sales per Commercial Customer (kWh)
2007	989,728	9,735	108,267	93,285
2008	991,761	9,835	108,649	92,714
2009	995,351	9,660	109,015	89,775
2010	996,790	9,719	109,205	90,003
2011	997,600	9,779	109,174	89,861
2012	997,941	9,925	108,987	90,291
2013	996,445	9,513	108,671	89,821
2014	999,574	9,529	108,802	89,429
2015	1,002,951	9,338	109,025	88,116
2016	1,005,759	9,246	109,390	87,168
Variance				
2007-2016		-5.0%		-6.6%
2012-2016		-6.9%		-3.4%

Source: DR 236 and 959

PSEG LI forecasts from 2017 through 2021 show a five percent decrease in sales and a four percent decrease in coincident peak demand. The decrease is sales in driven by an eight percent decrease in residential sales.[1]

System Planning

LIPA's service territory covers two jurisdictional planning areas: Zone K and the Long Island Control Area (LICA).

- Zone K is one of the eleven planning regions within New York State. Transmission planning for Zone K is coordinated with the New York Independent System Operator (NYISO) in development of its Gold Book, NYISO's annual report showing existing and forecast load and capacity data.
- The LICA is located within Zone K. The LICA planning area is an adjustment to Zone K to account for municipalities with self-generation, energy efficiency and cogeneration.

PSEG LI's Planning organization, shown in **Exhibit VII-4**, performs transmission and distribution planning for LIPA's system.[2] The Director of Planning, Resources, and Engineering reports to the Vice President of Electric Operations. The Vice President of Electric Operations reports to the President of PSEG LI.

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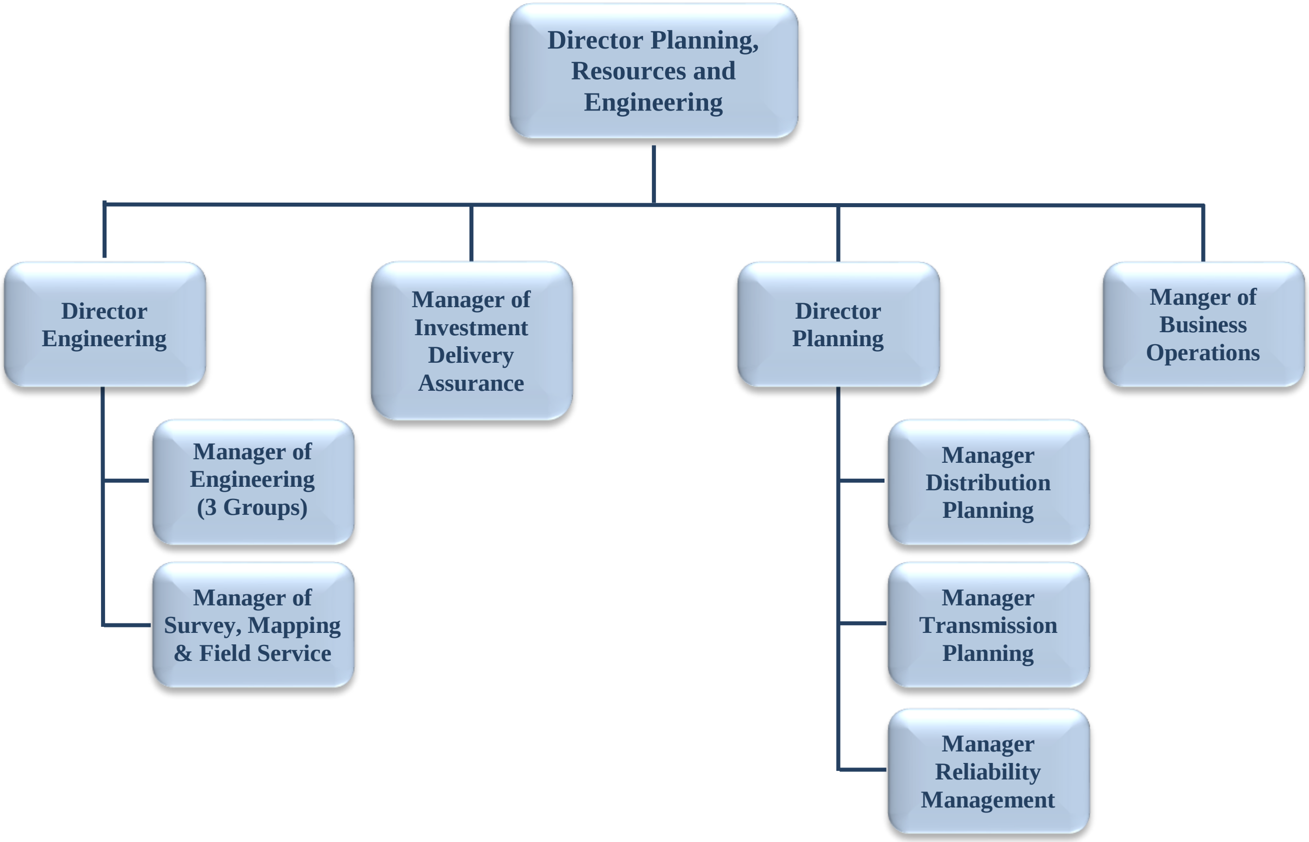
[1] DR 971 and 972

[2] DR 2 and 830

Exhibit VII-4
Planning Organization



Source: DR 830.

PSEG LI designs to the system coincident peak demand. Coincident peak demand is a product of the load forecasting function and is developed for both jurisdictional planning areas. The demand forecast includes weather-based probabilistic analyses. PSEG LI's design criteria stipulates a 50 percent normal weather load forecast for thermal analysis and a 95 percent extreme weather load forecast for voltage analyses.[3]

Transmission Planning uses forecast demand and known and planned system attributes (such as equipment ratings and configurations) to perform four categories of system studies:

- **Five-year and Ten-year Planning Studies** – Long-range studies are completed for the 5- to 10-year forecast timeframe and address the bulk transmission system and the underlying sub-transmission system, which supplies substations. This study also addresses specific load areas, including the area transmission system, substations and distribution feeders. Both of these types of studies are designed primarily to assess the ability of the system to deliver power to load centers and to serve customer load.

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[3] LIPA/PSEG LI Fact Verification

- **Seasonal Operating Studies** – Seasonal operating studies are a valuable reference tool for Transmission Operations for periods when the system is under peak load conditions. The operating study contains thermal and voltage limitations, voltage operating guidelines, must-run generation levels, and load transfer information that may be necessary upon contingency. In addition to being a valuable tool for the operation of the LIPA system, the results of the study identify reinforcements that are required to alleviate system constraints.

- **Interconnection Studies** – Transmission and distribution interconnection studies are designed to determine the required interconnection facilities and/or system reinforcements, if necessary, for specific generation projects. Projects connecting to the transmission system are also evaluated in accordance with the NYISO interconnection process.

- **Regulatory Studies** – These studies are required by North American Electric Reliability Council (NERC) and NYISO. NERC studies are defined in its Transmission System Planning (TPL) Standards. Typically, they are related to thermal overload analyses and critical infrastructure protection.

Transmission and distribution planning use a number of software systems and models to assist in developing planning studies, including the following:

- Power Technologies International's (PTI) Power System Simulator (PSS/E) – Used for system modeling the transmission system under steady state conditions
- PTI's PSSMOD File Builder – Used for data exchange between the NYISO and PSEG LI
- ASPEN – Used for short-circuit analysis
- PowerGEM Transmission and Reliability Assessment (TARA) – software tool with advanced steady state modeling
- Python – programming language for data automation and management
- PI DataLink and PI Process Book (PI) – interface with Supervisory Control and Data Acquisition (SCADA) system for real time system information
- CYME Power Engineering Software (CYME) – Software system to compute distribution system load transfers
- Area Load Forecast (ALF) – Used to develop load pocket forecasts.[4]

Planning at the distribution level is done at the substation transformer bank and feeder level. Distribution planning can be categorized as part quantitative and part qualitative. The quantitative aspect is average system growth determined by the load forecast. The qualitative aspect is determining how the average system growth impacts individual sections of the system. It is more difficult to determine exactly the timing and where new large individual load additions will occur. PSEG LI relies on the experience of the planning engineer.[5]

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[4] DR 925

[5] DR 868

PSEG LI's System Planning organization is primarily responsible for the development of LIPA's Five- and Ten-Year Transmission and Distribution Plan. The document provides the necessary infrastructure needs along with suggested system solutions. Additionally, System Planning supports the endeavors of other entities and initiatives, including:

- **NYISO's Gold Book** – Each year, the NYISO performs statewide studies of resource and capacity requirements as part of its annual Gold Book. The purpose of the Gold Book is to ensure that New York has adequate generation and transmission capacity to supply current future and state load. In addition to supporting the planning effort, PSEG LI supports the NYISO in the development of the summer and winter operating studies. These studies identify power transfer and thermal limitation at key areas in New York.[6]

- **North American Electric Reliability Corporation (NERC**) – Bulk Energy Supplier (BES) certification -- In July 2016, LIPA obtained its BES certification from NERC. To obtain certification LIPA must comply with the Critical Infrastructure Protection and Reliability planning standards as specified by NERC.[7] This certification was historically held by the NYISO.

    - In 2014, the Federal Energy Regulatory Commission (FERC) approved mandatory and enforceable reliability standards for the bulk power system. This authority was then delegated to NERC. The definition for BES was expanded to all transmission greater than 100kV.
    - The impact on LIPA was significant as the entire LIPA 138 kV transmission system and its associated elements were made subject to NERC reliability standards. This expanded transmission planning's analyses in critical infrastructure protections, control and protection, geomagnetic disturbance, contingency analysis, operating limits and corrective action plans.[8]

- **New York State's Reforming the Energy Vision (REV) initiative** – The electric industry is undergoing a period of tremendous change due to factors such as innovative technology, an increasingly digital economy, the need to address aging infrastructure, climate change, advancement in distributed generation technologies and an increasing gap between the traditional electric utility function and future requirements.[9]

  The State of New York is responding to these challenges. In April 2014, the New York Public Service Commission (PSC or Commission) commenced its REV initiative to reform New York State's energy industry and regulatory practices. This initiative promotes more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, wider deployment of distributed energy

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[6] DR 238

[7] DR 51 and IR 106

[8] DR 951

[9] CASE 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015).

> resources, such as micro grids, on-site power supplies, and storage. It will also promote greater use of advanced energy management products to enhance demand response and efficiencies.
>
> On February 26, 2015, the PSC issued an order adopting a regulatory policy framework and implementation plan for REV. One element of REV is that distributed energy resources (DER) will be integrated into the planning and operation of electric distribution systems, to optimize system efficiencies, secure universal, affordable service, and enable the development of a resilient, climate-friendly energy system. DER includes end-use energy efficiency, demand response, distributed storage, and distributed generation. DER will principally be located on customer premises, but may also be located on distribution system facilities.

The PSC, in its regulatory role, is guiding the implementation of REV through the development of structure and sponsorship of collaborative sessions between stakeholders. **Exhibit VII-5** provides a timeline of past REV events. LIPA and PSEG LI implement policy consistent with REV through their EE and Renewables program as well as Utility 2.0. PSEG LI and LIPA are not directly subject to commission jurisdiction regarding REV, but are consistent as possible with PSC decision-making.

Exhibit VII-5
REV Timeline and Events

Date	Event	Description
April 2014	Initiation of REV Proceeding • Case 14-M-0101, Reforming the Energy Vision, Order Instituting Proceeding (issued April 25, 2014) • (Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding (issued April 25, 2014) and DPS Staff to issue a straw proposal on Track Two by June 1, 2015.) • Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan, referenced as the "Track One Order" or "Framework Order" (issued February 26, 2015)	Establishment of two tracks: DER Markets and Ratemaking Practices and six objectives: • Enhanced customer knowledge and tools • Market animation and leverage of customer contributions • System wide efficiency • Fuel and resource diversity, • System reliability and resiliency • Reduction of carbon emissions.
August 22, 2014	Track One Straw Proposal	PSC Recommended: • The PSC should adopt the basic elements of the REV vision and proceed with implementation as proposed in the straw proposal. • Existing utilities should serve as Distributed System Platform (DSP) providers subject to performance reviews. • Customers and energy service providers should have access to energy usage information to enable customers to assess the economic value of off-peak usage. • Where utility affiliates participate in DSP markets within the service territory operated by their parent company, appropriate market power protections must be in place. • As part of the transition toward market-based approaches to increase levels of efficiency and renewable energy, utilities should integrate energy efficiency into their regular operations and should take responsibility for procurement of renewable energy.
December 2014	PSC encourages coordination between utilities and third-parties	Develop potential demonstration projects that will inform decisions with respect to developing DSP functionalities, measuring customer response to programs and prices associated with REV markets, and determining the most effective implementation of DER.

Date	Event	Description
January 8, 2015	Order for establishment of the Market Design and Platform Technology (MDPT) Working Group Process Case 14-M-0101, Reforming the Energy Vision, Report of the Market Design and Platform Technology Working Group (issued August 17, 2015), p. 15.	Select, convene and coordinate with the Rocky Mountain Institute and the NYS Smart Grid Consortium, two closely related groups, to address market design and platform technology.
February 26, 2015	PSC Order for REV Regulatory Policy Framework and Implementation Plan Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (referenced as the "Track One Order" or "Framework Order") (issued February 26, 2015), p. 48.	One element of REV is that DER will be integrated into the planning and operation of electric distribution systems, to optimize system efficiencies, secure universal, affordable service, and enable the development of a resilient, climate-friendly energy system. DER includes end-use energy efficiency, demand response, distributed storage, and distributed generation. DER will principally be located on customer premises, but may also be located on distribution system facilities. The REV reforms envisioned are comprehensive and in their early stages of development. The PSC examined the establishment of a DSP to manage and coordinate DER, and provide customers with market data and tools to manage their energy use. The PSC also examined how its regulatory practices should be modified to incent utility practices to promote REV objectives. Following the proceeding, a two-phased schedule with policy determinations for the DSP and related matters was expected in early 2015 and for regulatory design and regulatory matters, later in 2015.
July 28, 2015	PSC White Paper on Ratemaking Case 14-M-0101, Reforming the Energy Vision, DPS Staff White Paper on Ratemaking and Utility Business Models (issued July 28, 2015).	The ratemaking paradigm should be used to encourage, not deter or delay the realization of customer benefits through optimal investment in and management of the system including the deployment and use of DER. Misalignment between utilities' financial interests and operational changes or transactive obligations that improve economic and efficient energy delivery, including support of the continued growth of DER penetration, introduces friction that is detrimental to the successful achievement of REV's objectives and its attendant benefits. Accordingly, the focus of the ratemaking reforms discussed in the DPS Staff white paper is to identify mechanisms that will reduce or eliminate this friction and achieve the desired alignment of interests.
August 7, 2015	MDPT Working Group Report Case 14-M-0101, Reforming the Energy Vision, Report of the Market Design and Platform Technology Working Group (issued August 17, 2015)	Recommendations to the Department of Public Service (DPS) concerning DSP market design and platform technology issues and looking for common ground between participants.

Date	Event	Description
April 20, 2016	Case 14-M-0101 Order Adopting Distribution System Implementation Plan Guidance	Orders DSIP filings to describe and analyze certain specified processes and data related to distribution system planning and distribution grid operations that account for distributed energy resources. Attachment 1 to the Order lists Distribution System Planning related filing requirements related to Forecasting Demand & Energy Growth
August 1, 2016	Clean Energy Standard (CES) Case 15-E-0302, Clean Energy Standard	PSC Order adopting 50 percent renewable energy standard and goal of 40 percent reduction in greenhouse gas emissions by 2030.
October 31, 2016	CES Implementation Plan	Permits approved DERs to be considered part of the CES.
April 5 and 6, 2017	Technical Conference on the Value of Distributed Energy Resources Case 15-E-0751 – Value of Distributed Energy Resources	The purpose of the conference is to set forth efforts to calculate the values of demand reduction, locational system relief, installed and capacity.

The August 2015 MDPT report provided a broad range of recommendations including an operating structure, roles and responsibilities, technical needs, and barriers to success. The REV scope envisioned is broad and includes numerous emerging regulatory process interrelationships and technological capabilities. From the perspective of system planning, REV calls for:

- Enhanced distribution planning – to integrate DERs into the distribution system and improve coordination between distribution and transmission system planning activities.
- Expanded distribution grid operations – expanding grid operations to better optimize load, supply and other power parameters at the local distribution level.
- Distribution market operations – managing market operations and processes, and administering markets.
- Data requirements – making customer and distribution system data available to market participants at a degree of granularity and in a manner that will best facilitate market participation.
- Platform technologies – including geospatial models of connectivity and system characteristics, sensing and control technologies, optimization tools for DER capabilities and generation output (existing and new DERs).
- A central element of REV is the creation of a system operator at the retail/distribution level. The Track One Order and the MDPT report recognized that the functional center of the REV framework is the DSP "provider" – the electric distribution utility.

During the course of the audit, NorthStar requested benchmarking studies. While comparing what other utilities in New York have done with respect to REV implementation and various aspects of Load Forecasting, PSEG LI did not provide any relevant studies.[10]

Load Forecasting prepares a forecast annually. NorthStar adopted the following nomenclature to distinguish each year's forecast.

- The 2015 Load Forecast was prepared in third quarter 2014.
- The 2016 Load Forecast was prepared third quarter 2015.

The findings and conclusions discussed in this chapter are based on the 2015 Load Forecast and the 2016 Load Forecast and their associated methodologies. PSEG LI adopted a new forecasting methodology for the first 42 months of the 2018 Load Forecast. While NorthStar reviewed the new methodology, the timing of this audit and the timing of the 2018 Load Forecast prevented any quantitative assessment.

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[10] DR 86 and 891

B. LOAD FORECASTING

Evaluative Criteria

- Are the models, assumptions, key drivers and other inputs used by PSEG LI to forecast local and system-wide load requirements appropriate?
- Is PSEG LI's methodology for developing a load forecast appropriate and adequately justified? Does PSEG LI utilize both a top-down and bottom-up aggregation methodology? Are the two methodologies reconciled and do they produce increased accuracy and more efficient allocation of system resources?
- Does PSEG LI 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, etc.), energy efficiency, and other similar factors given appropriate consideration in the forecasting process?
- Do the load forecasting functions/products meet the needs of finance and rates, supply procurement, regulatory compliance, system planning and other organizations within PSEG LI?
- Does PSEG LI have access to and use best available data to support implementation of energy efficiency, demand response and other initiatives?
- Are forecasting functions organized and staffed appropriately?
- Is the electric load forecasting process reviewed and changed sufficiently to consider policy initiatives that could have significant impact on load and energy requirements?
- Are system-wide and substation-specific forecasts accurate and appropriately considered in the system planning processes that address infrastructure adequacy and future load requirements?
- Does PSEG LI evaluate the impact of distributed energy resources (DERs) penetration on company-wide and regional forecasts? Does PSEG LI incorporate the forecasts of DER providers? Does PSEG LI coordinate, solicit, or model DER marketing activities?
- Does NYISO affect PSEG LI's forecasting in an appropriate manner?
- Are the PSEG LI system load forecasts accurate, and are deviations between the forecasts and actual experience investigated and promptly corrected?

Findings and Conclusions

1. PSEG LI's Load Forecasting functions are effectively organized and staffed. PSEG LI employs qualified staff that has the appropriate skill sets and produces the annual load forecasts and specialty studies as necessary.

- As shown in **Exhibit VII-6,** Load Forecasting is located in PSEG LI's Planning and Analysis group in Power Markets. Two organizations provide support to the load forecasting function: PSEG LI Customer Operations' Load Research group, and PSE&G's Energy Efficiency organization.

  - Customer Operations' Load Research group develops customer load shapes. Load shapes are used for demand forecasting and for settling wholesale energy transactions associated with the LI Choice program. Customer Operations' Load Research provides annual work products based on load research primarily to determine customer class contribution to system peak and hour load shape.
  - The primary work product of the Energy Efficiency organization is the planning, quantification and marketing of PSEG LI's energy efficiency programs. The impact of energy efficiency is a post-model adjustment that has implications in forecasting system growth requirements.

- The Load Forecast group supports different planning organizations throughout PSEG LI, and obtains data from numerous internal and external sources. Therefore, it has more than one appropriate organizational location, including its current placement in Power Markets. Prior to September 2017, Load Forecasting was part of the Electric Operations organization.[11]

Exhibit VII-6

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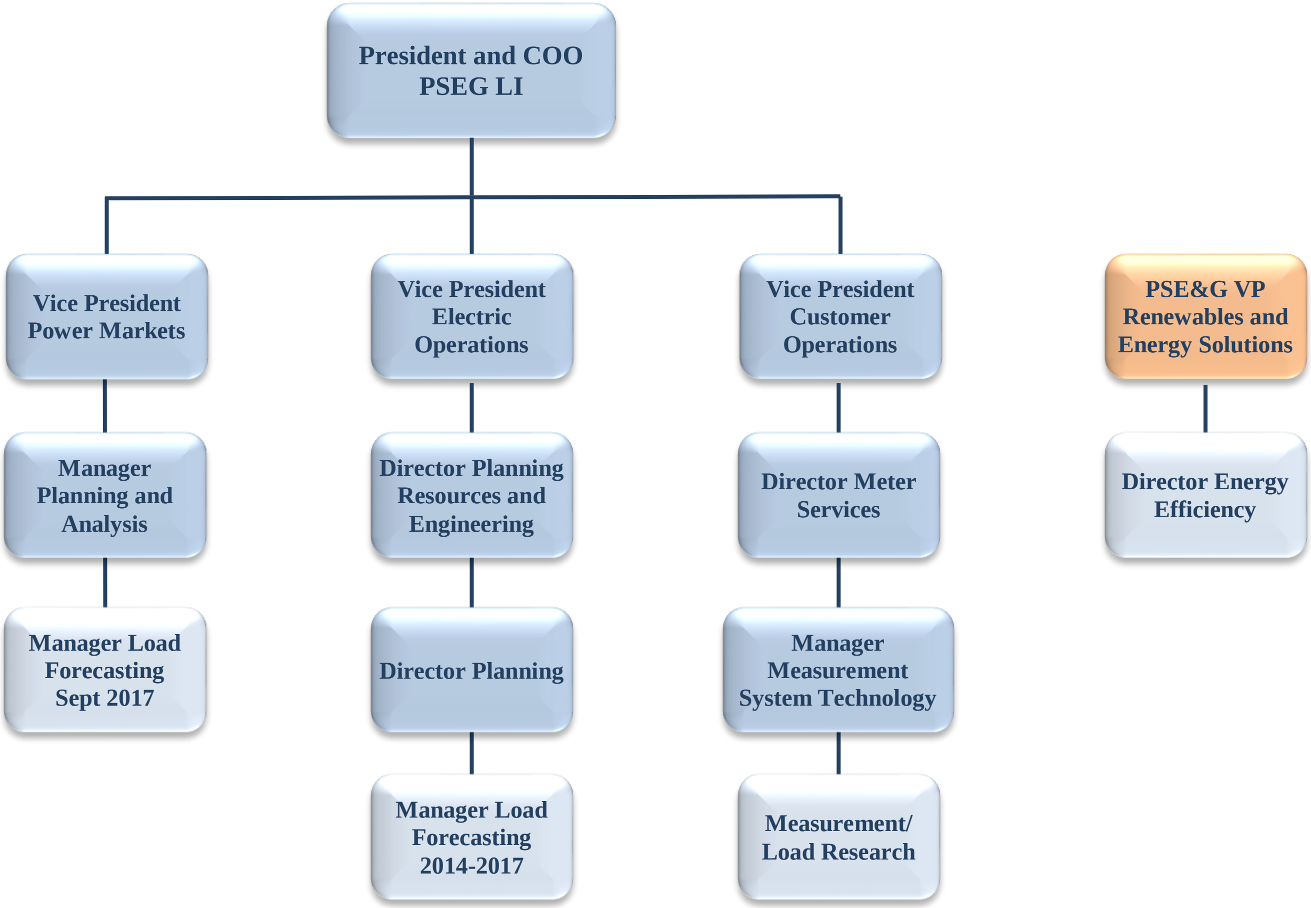
[11] DR 2 and 830



Source: DR 2 Attachment 2, DR 830 and https://www.pseg.com/family/leadership/pdf/mccormick.pdf.

- PSEG LI Load Forecasting is staffed appropriately.
  - PSEG LI's Load Forecasting Manager has an advanced degree in mathematics and statistics, almost twenty years of load forecasting experience, and experience in utility operations and computer systems.[12]
  - The Load Forecasting Manager is supported by a Load Forecast Specialist.[13]

- PSEG LI Customer Operations' Load Research group is organized and staffed appropriately.
  - Load Research's location in the meter services organization is reasonable. Load Research is responsible for the selection of the data sample, installation of interval data recorders (meters) and the collection of monthly data.
  - The supervisor of Load Research and Retail Settlement reports to the Measurement/Load Research organization found in **Exhibit VII-6.** He is

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[12] DR 56, 58, 657, 840

[13] DR 854

  - responsible for administering the load research program and developing load shapes has a degree in mathematics and ten years of load research experience across multiple utilities.

- PSEG LI's Energy Efficiency group is organized and staffed appropriately.
  - The Director of Energy Efficiency is a PSEG LI resource that reports to the Vice President of Renewables and Energy Solutions at PSE&G in New Jersey and to the PSEG LI Vice President of Customer Operations in a "dotted-line" relationship.
  - Energy Efficiency is another organization that has more than one appropriate location. The current location allows coordination with Customer Operations and collaboration with PSE&G.
  - The Director of Energy Efficiency has over 30 years of utility experience, a degree in engineering and experience in marketing and developing energy efficiency programs for several electric utilities.[14]

2. **During the period assessed (2014-2016), PSEG LI had a sound methodology to forecast system-wide and local load requirements, with segmented customer modules and appropriate assumptions, data sources and horizons.**

- PSEG LI's Load Forecasting group prepares annual Zone K baseline energy and demand forecasts. The baseline forecasts show the total potential energy consumption and coincident peak demand for LIPA's service territory and the independent municipal utilities within LIPA's service territory, without any adjustments. PSEG LI uses the Zone K baseline forecasts to prepare regional and local load analyses.[15]

- To develop the baseline energy forecast, Load Forecasting uses econometric regression modeling to forecast residential and commercial/industrial (C/I) electric sales, which together account for about 97 percent of LIPA's total annual sales. The Forecasting group uses industry-specific spreadsheet models to forecast the remaining three percent of electric sales relating to other public authorities, street lighting and electric vehicles.[16]

- PSEG LI develops a single model for the sales forecast in the residential sector and eight models for the sales forecast in the C/I sector representing distinct segments or sectors for Long Island: Manufacturing; Trade, Transportation and Utilities; Leisure and Hospitality; Financial Activities; Information; Business Services; Education and Health Services; and, Government.[17]

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[14] DR 2, 812, 830, 840

[15] DR 654 and 655

[16] DR 163

[17] DR 164

- Each forecast is developed based on the average annual use per customer multiplied by the number of customers.[18] In the forecast models, the average annual use per customer is a dependent variable, and assumptions regarding the weather and economy are independent variables.

- LIPA's energy forecasts are based on information and usage patterns specific to Long Island and its customers. **Exhibit VII-7** presents an overview of PSEG LI's residential and C/I sales forecast econometric regression models.

Exhibit VII-7
Overview of Residential and C/I Sales Forecast Econometric Regression Models

Attribute	Residential	Commercial/Industrial
Number of Equations	1	8 (one for each sector)
Dependent Variable	Annual Electric Use per Customer	Annual Electric Use per Customer for each sector
Independent Variables (Assumptions)	▪ Cooling Degree Days ▪ Median Real Home Price ▪ Real Customer Income ▪ Real Gross LI Product/Customer ▪ Employees/Customer ▪ Real Price of Electricity	▪ Heating Degree Days ▪ Cooling Degree Days ▪ Real Customer Income ▪ Real Household Income ▪ Real Gross LI Product/Customer ▪ Households/Customer ▪ Employment/Customer ▪ Real Price of Electricity

Source: DR 163.

- PSEG LI obtains "assumption" data from Moody's Analytics, with the exception of normal cooling and heating degree days, number of customers and the price of electricity, which are developed internally.[19]

- PSEG LI maintains a comprehensive database of historical usage that supports model development, which includes:
  - Historical customer count by sector
  - Average annual usage by customer class
  - Historical weather data from the National Weather Service.
  - Equations for each model are tested for fit and statistical relevance.[20]

- Out-of-model adjustments are made to account for demand-side management programs. The C/I model also is adjusted for cogeneration (which also includes a small amount of reductions due to fuel cells, energy storage and micro-turbines).[21]

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[18] DR 163
[19] DR 163
[20] DRs 163 and 229
[21] DR 163

- The Zone K baseline energy forecast is used to develop a baseline peak demand forecast.

  - The forecast is developed for each energy forecasting sector and combined to create the system coincident peak demand.
  - The specific inputs include most recent weather system normalized peak demand and sales and sector load shapes.
  - Sector load shapes are used to determine the contribution to peak from each sector.
  - A load factor for each sector is then determined.
  - The load factor is applied to forecast sales for each sector and combined to calculate coincident peak demand.[22]

- PSEG LI develops 20-year energy and demand forecasts. The first ten years are developed using regression equations. The last 10 years are based on the years 6 through 10 trends.[23]

3. **PSEG LI appropriately reconciles its top-down and bottom-up models to determine weather-normalized sales and the weather-normalized annual peak load. This methodology adds refinement to the demand forecasting process, resulting in increased accuracy for infrastructure planning.**

- PSEG LI uses "Top-Down" and "Bottom-Up" processes as described below.

- Bottom Up: As discussed in Conclusion 2, Load Forecasting uses economic regression modeling to forecast approximately 97 percent of its annual sales (residential and C/I sectors), and other modeling methodologies for the remaining three percent.[24] Load Forecasting uses customer use data to develop load factors for the residential and nonresidential sectors. The load factors are applied to the sector sales forecasts to develop the annual system peak load forecast.[25]

- Top Down: Each month, integrated hourly system loads from the SCADA system are summed into daily totals and combined with experienced daily weather to develop a regression model. Each model is used with normal daily weather to determine the system energy use attributable to weather conditions different from normal.

  - The ratio of weather normalized to experienced energy is applied to calendar-month booked sales to estimate weather normalized sales.
  - Then fixed percentages of the monthly weather adjustments are applied to the residential and C/I sectors: the split is 70 percent to the residential sector and 30

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[22] DR 163
[23] DR 162, 163, and 309
[24] DR 287
[25] DR 287

percent to the commercial-industrial sector for May through September and 50/50 for the remaining months.[26]

- The "Bottom Up" energy and demand forecasts are reconciled to the "Top Down" weather-normalized sales and the weather-normalized annual peak load, using a calibration factor which is then used to adjust the new peak load forecast.[27]
  - The SCADA weather-normalized peak demand is compared to the results from the load forecasting peak demand model. The difference between the two numbers is called model error. The model error is then added to the forecast of peak demand for each year of the forecast. Typically, this amount is very small: in the range of a few MWs.
  - For each month, the difference in actual hourly data and calculated normal weather hourly data is summed. The amount of energy is split between the residential and commercial sector based on load research data. It is then applied to each sector's actual sales to determine monthly weather normalized sales.[28]

4. **PSEG LI's forecast of monthly sales and the weather normalization of actual monthly sales are currently based on estimated data. This is a common situation at utilities where a calendar month of historical sales does not align with bimonthly billing and twenty billing cycles each month. PSEG LI is exploring the possibility of using SCADA data to determine actual sales amounts.**

- Actual monthly sales are estimated based on billed monthly sales. Billed sales include both current month's usage and the previous month's usage. Booked sales (actual monthly sales) include a portion of the current month's billed sales and a portion of the following month's billed sales. This is due to billing cycles spanning multiple months and bi-monthly residential meter reads.[29]

- Billed sales are converted to monthly booked sales through an algorithm in the Customer Accounting System (CAS). The process involves a temperature-based allocation of billed sales and an estimate of the following month's sales.[30]

- The reported actual sales are then weather normalized using the top-down, bottom-up methodology. The weather normalized result is then compared to the forecast.

- The monthly sales forecast is based on an allocation of the annual forecast. Each month CAS estimates booked sales. The percentage of annual sales by month is determined by dividing the CAS monthly estimate by annual sales. For each of the previous three years, the monthly percentages are averaged and applied to the annual

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[26] DR 287
[27] DR 287
[28] IR 100
[29] DR 810
[30] DR 810

forecast to determine monthly forecast sales. The process is based on the average of an estimate not on actual recorded history, resulting in an estimate. [31]

- Utilities have a variety of methods for the conversion process, including load shape fitting and temperature-based regression models. PSEG LI is reevaluating the process of converting billed sales to booked sales. Total system sales including losses are collected through the SCADA system. PSEG LI has engaged the services of a consultant to develop a line loss study. The study is scheduled to be complete in September 2018. When the study is complete, PSEG LI will evaluate the use of SCADA data in the calculation to determine booked sales.[32]
- In 2017, PSEG LI adopted a quarterly interval forecasting model. PSEG LI now allocates the quarterly forecast based on the previous three years' quarterly history.[33]

5. LIPA appropriately hired an outside consultant to conduct a review of PSEG LI's sales forecasting, and PSEG LI has begun to evaluate and implement the consultant's recommendations.

- In 2016, LIPA engaged the services of a consulting firm to perform a review of PSEG LI's sales forecast process compared to industry best practices. The final report, dated February 2, 2017, found that much of the forecasting process is consistent with industry best practices.[34]
- The consultant made a number of recommendations that may improve PSEG LI's sales forecasting accuracy, including:
    - Changing the forecasting unit from annual to monthly or quarterly and eliminate the need for a "jump-off" point.[35]
    - Developing sector-wide forecasts instead of industry-specific forecasts for commercial and industrial sales.
    - Communicating with management and users regularly to increase understanding of the forecasting process and its limitations.
    - Revising the weather normalization routine to avoid using fixed distribution of weather related sales to each sector.
    - Revising the Energy Efficiency Adjustment Process from a system-wide process to an incremental process.

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[31] DR 811

[32] DR 735, email dated March 14, 2018, and LIPA/PSEG LI Fact Verification

[33] DR 1017

[34] DR 309

[35] The jump-off point is the result of a misalignment between the last historical data point and when a forecast is prepared. Forecasting should use the most recent historical data whenever available. With the annual forecasts at PSEG LI, the last actual data point is 6 months old. The actual monthly data from current year is not used in the forecast. The jump-off point is a calibration between predicted end-of-year sales based on actual sales to date and model prediction for end of year.

  - Collaborating with non-forecasting colleagues to improve their understanding about the forecast, and developing a monthly variance report that explains sources of the monthly variance.
  - Continue the transition to Advanced Metering Infrastructure (AMI). AMI is an advanced metering platform the records energy consumption in 15-minute time intervals and communicates the data to the utility. When fully implemented, AMI would provide actual monthly sales.[36]

- At the time of the audit, PSEG LI was in the process of testing, evaluating and implementing the consultant's recommendations.

  - The sales forecast developed in 2017 (for the years 2018 through 2022) will include a quarterly derived forecast for three years and an annual derived forecast for years 4 and 5.[37]
  - PSEG LI's forecasting organization is expanding its material and outreach to affected organizations to clarify impact of weather on sales to assist other organizations in their planning activities.[38] PSEG LI also prepares a monthly sales analysis. The analysis includes:

    - Weather – Cooling degree days (CDD), heating degree days (HDD), and average temperature to normal
    - Economic Drivers (employment) – actual to forecast
    - Energy Sales – Actual, weather normalized, and forecast
    - Energy Sales by Sector
    - Energy Sales compared to previous year
    - Energy use per customer.[39]

- Based on the consultant's study, PSEG LI has investigated changes to its forecasting model as shown in **Exhibit VII-8**.

Exhibit VII-8
PSEG LI Examinations of Potential Sales Forecasting Model Changes in 2017

Potential Change	PSEG LI Actions
Quarterly or monthly model	PSEG LI is in the process of evaluating a quarterly model. The quarterly model was developed in August 2017.
Impact of using 30 years of data on short-term results	PSEG is evaluating short-term for the first three years of the forecast using both 30 years of annual data and 7/1/2 years (30 observations) of quarterly data. This will be a component of the 2018 Load Forecast.
Reduction in the number of C/I models	PSEG is evaluating a single C/I model and comparing results with the current eight sector C/I models. This will be a component of the 2018 Load Forecast.

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[36] DR 309 Attachment 1.
[37] DR 731 and 813; IR 174
[38] DR 813
[39] DR 236

Source: DR 309, 731, 732, and 733.

- Findings from these evaluations include:
    - A monthly model would add to the billed to booked sales issue (see Conclusion 4).
    - A quarterly model would eliminate a portion of the billed to booked issue.
    - PSEG LI currently prepares mid-year forecasts, which entails forecasting to the end of the current year. A quarterly forecast would eliminate the timing "jump-off" and allow history to align with forecast.
    - Side-by-side comparisons between the new quarterly forecasting methodology and the old annual forecasting model were conducted for a three-year horizon on three separate occasions as a new model was refined. The new model results were encouraging in that the results were compatible between the two models. The final comparison found approximately 0.9 percent variance between the final model specification and the old model results.[40]

6. PSEG LI's load forecasts meet the planning needs of PSEG LI, LIPA and the NYISO. Forecasts are tailored to each organization's needs, including considerations for cogeneration, energy efficiency, demand reductions programs, and the Long Island Choice program.

- The PSEG LI forecast has six post-model adjustments, resulting in six levels of energy and demand forecasts. Each level addresses specific regulatory initiatives and planning considerations (jurisdictional levels). **Exhibit VII-9** provides the post model adjustments to the baseline (Zone K before reductions) forecast.

- PSEG LI develops demand and energy forecasts with probabilistic scenarios for weather. The base forecasts are developed with normal weather resulting in a 50 percent confidence interval. Each jurisdictional level is developed with varying confidence intervals as requested by users of the load forecast.

Exhibit VII-9
Jurisdictional Forecasts

Forecast	Adjustment	Confidence Intervals	Primary Purpose	Supported Organization(s)
Zone K Before Adjustments		50%	Baseline Forecast	
Zone K	Reduction for Energy Efficiency, Cogeneration, and Renewable Resources	10%, 50%, and 90%	Support NYISO "Gold Book"	NYISO

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[40] DR 731 and 1016

Forecast	Adjustment	Confidence Intervals	Primary Purpose	Supported Organization(s)
Long Island Control Area (LICA)	Reduction for municipal self-supply	80% and 1 in 30 50%, 80%, 90% and 1 in 30	T&D Operations Resource, T&D Planning	T&D Operations System Planning
LIPA Booked Sales	Reduction for NYPA firm supplies	50%	Revenue Forecast	Finance Rates
LIPA Retail Delivery	Reduction for NYPA hydro	10%, 50%, and 90%	50%, 80%, 90%, 95% and 1 in 30	Power Resources
LIPA MAPS and ICAP/UCAP[41]	Reduction for Recharge NY	50%, 80%, 90%, 95% and 1 in 30	LIPA Installed Capacity in support of "Gold Book"	NYISO
Load Serving Entity	Reduction for Long Island Choice	50%, 80%, 90%, 95% and 1 in 30	50%, 80%, 90%, 95% and 1 in 30	Rates

Source: DR 161, 655, 656 and 657.

- The Zone K before adjustments is the base forecast. It is adjusted for energy efficiency, cogeneration, and renewables, resulting in the Zone K forecast. The adjustments are based on annual audits of demand-side management and energy efficiency installations and valuations and PSEG LI implementation plans.[42]

7. PSEG LI obtains the best available data for evaluating and quantifying opportunities for energy efficiency, demand response and other initiatives.

- PSEG LI engaged the services of a consulting firm in 2015 and 2016 to quantify energy efficiency demand and energy savings. The final reports provide an analysis of portfolio performance by customer sector and program. This annual study provides an independent quantification of:
  - Post model adjustments (Zone K Before Reductions).
  - PSEG LI success of marketing energy efficiency throughout the service area.
  - Consumer acceptance and preference of specific programs.[43]
- PSEG LI engaged the services of another consulting firm in 2016 to conduct an Energy Efficiency Potential Study. This study provides PSEG LI with:
  - A residential sector appliance saturation survey. This survey was a statistically relevant sample of type of installed residential electrical equipment (end use).

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[41] MAPS = Multi-Area Planning Study, ICAP = Installed Capacity, and UCAP = Unforced Capacity

[42] DR 161, 168, and 310

[43] DR 310

  - The study also provided a technical and economic analysis of the realistically achievable EE opportunities through utility programs. The analysis is specific to sector and industry.[44]

- PSEG LI's Energy Efficiency organization reports to the VP of Renewables and Energy Solutions at PSE&G (New Jersey). This relationship with PSE&G (New Jersey) provides opportunities for collaboration and transfer of knowledge.[45]

8. PSEG LI uses system-wide and area-specific forecasts to improve its infrastructure investment decisions.

- Load forecasting develops forecasts to assist Transmission and Distribution Planning in considering infrastructure investment decisions. Specific forecasts include:

  - System coincident peak demand at normal weather
  - Weather probabilistic system coincident peak demands
  - Regional and load pocket demand forecasts at extreme conditions
  - Special feeder/bank load studies (South Fork Project).

- Unique and specific geographic demand changes are addressed in the winter and summer feeder and bank forecasts prepared by the Distribution Planning Organization. The forecast is developed by:

  - Obtaining annual peak on each feeder and bank from the Energy Management System
  - Adjusting bank and feeder peak for normal weather from actual weather
  - Apportioning the system load forecast to each feeder and bank (gradual growth)
  - Adjust feeder and bank forecasts for expected lump load changes
  - Determining system constraints
  - Preparing an annual system bank report for all 368 distribution station banks, that identifies current bank load, forecast lump load additions, demand reductions to DER resulting in a comparison of forecast demand to bank capability.[46]

9. PSEG LI includes the impact of DER on its company-wide forecasts.

- PSEG LI applies a post model adjustment for energy efficiency and load reduction programs. The forecast is also adjusted for cogeneration which includes in part fuel cells, micro turbines, and energy storage technologies. The adjustment results in a decrease in both energy and peak demand.[47]

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[44] DR 168

[45] DR 2

[46] DR 188, 232, 233, 238, 862, 868

[47] DR 164, 166, 234, and 734

- DER additions to the system, as tracked by PSEG LI Power Asset Management, are included in the load forecast. PSEG LI does not use DER provider forecasts in its forecasting platform.

- PSEG LI does not, per se, forecast DER penetration on a regional basis. However, when a DER solution is under consideration, load forecasting supports system planning in quantifying and forecasting the effects of a DER solution.[48]

10. The relationship with the NYISO in the development of load forecasts is appropriate. Working with the NYISO provides opportunities for the exchange of knowledge and for collaboration.

- The NYISO Load Forecasting Task Force is a collaborative effort between the NYISO and the participating utilities from each of Planning Zones A through K. PSEG LI's manager of load forecasting, both in his positions at PSEG LI and National Grid, has chaired this task force since 2009.

- The primary mission of the Load Forecasting Task Force is to establish the data reporting requirements, the methodology for weather normalization, and the methodology for forecasting load.[49]

- Ultimately each utility must produce its own load forecast. The state-wide collaboration between the NYISO and the utilities' forecasters provides an opportunity for improved data and model development.

11. While PSEG LI's system peak demand forecasts are quite accurate, its system-wide sales forecasts are less accurate. As discussed in Conclusions 5 and 12, LIPA and PSEG LI are taking steps to address the accuracy of its sales forecast.

- As shown in **Exhibit VII-10**, the 2014 through 2016 peak demand forecasts had variances between 0.3 and 1.6 percent on a system-wide level. The forecasts for 2016 show increased accuracy with each subsequent forecast.

Exhibit VII-10
Coincident Peak Demand Variance

	Variance		
	2014	**2015**	**2016**
Weather Adjusted Actual Peak (MW)	5,411	5,372	5,356
2014 Forecast	0.1%	1.0%	1.6%
2015 Forecast		1.1%	1.1%
2016 Forecast			0.3%

Source: DR 162.

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[48] DR 234

[49] http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/load_fcst_mnl.pdf

- On a rolling 12-month basis, PSEG LI's forecast overestimated actual weather normalized sales by approximately 2.5 percent (500 GWh) in 2014 and 2015.[50] This overestimate results in lower than anticipated revenue, impacting the Revenue Decoupling Adjustment (RDA). The RDA is a supplemental charge on customer bills that recoup unrealized revenues in the following years. Over collection of revenues result in a refund in subsequent years on customer bills. Based on $3.4 billion in annual revenue, the under-collection of 2.5 percent results in approximately $85 million to be recouped through the RDA.[51]

- In 2014, both PSEG LI and the DPS developed sales forecasts for 2015 and 2016. DPS developed the 2016 approved sales forecast for the 2017 rate case. As shown in **Exhibit VII-11**, PSEG LI's sales forecast for 2015 and 2016 had variances of 2.7 and 4.5 percent, while the DPS' forecast had variances of 3.4 and 5.3 percent.

Exhibit VII-11
PSEG LI and DPS Rate Case 2015 and 2016 Sales Forecast Variances
(Based on 2015 Load Forecast)

Year	Actual Sales (GWh)	PSEG LI		DPS	
		Forecast (GWh)	Variance	Forecast (GWh)	Variance
2015	19,557	20,077	-2.7%	20,229	-3.4%
2016	19,389	20,268	-4.5%	20,419	-5.3%

Source: DR 650 Attachment 2.

- There are significant differences between the PSEG LI and DPS forecasting methodologies. **Exhibit VII-12** provides a comparison of the technical differences. PSEG LI modified its methodology in late 2017 for its 2018 forecast. For comparison purposes, the new model parameters are also shown in **Exhibit VII-12**.

12. PSEG LI investigated and corrected the cause of its 2016 sales forecast variance.

- PSEG LI performed an internal analysis of its 2016 Load Forecast sales variance and reported to the Board's Operations and Oversight Committee on July 26, 2017. PSEG LI determined that the 2016 sales variance of -3.3 percent (as compared to -4.5 percent in the 2015 Load Forecast) was in part attributable to the greater than expected market penetration of light-emitting diode (LED) technology and an unprecedented number of non-incentive-based residential roof-top solar installations.

- NorthStar reviewed PSEG LI's analysis and confirmed the results. NorthStar determined that absent the unexpected impact of LEDs and roof-top solar installations, the sales forecast variance would be -2.3 percent.

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[50] DR 309 Attachment 1

[51] DR 761 and http://www.lipower.org/pdfs/company/papers/LIPA%202017%20BUDGET%201-6-2017.pdf and https://www.psegliny.com/page.cfm/AboutUs/ServiceRates/RDA

- NorthStar found that the unforeseen increase in non-incentive-based roof top solar installations represents 6 percent of the sales variance (41 GWh). PSEG LI forecasts the number of incentive-based roof-top solar installations. Historically, the number of non-incentive based roof-top installations was insignificant. In 2016, 40 percent of all installations were non-incentive-based, indicating a market shift.
- NorthStar found that the increased use of LED technology represents 24 percent of the sales variance (157 GWh).
- Adding back the lower sales attributed to roof-top solar and LEDs, the sales forecast would have a variance of -2.3 percent, indicating the model requires "fine-tuning" rather than an entire rebuild. This is consistent with the consultant's study discussed in Conclusion 5.[52]
- The resulting Year 2017 forecast of residential use per customer dropped from 9,909 kWh/year in the 2014 Forecast to 9,156 kWh/year (7.6 percent) in the 2017 Forecast. Use per customer and number of customers are the primary drivers to the residential sales forecast.[53] There was divergence between the econometric models to predict customer use and actual customer end-use. Econometric models use past experience to explain future behavior. In light of a technology shift, past behavior may not predict future behavior. The change from traditional incandescent lighting to a rapid increase of the adoption of LED technology could not adequately be represented in the residential econometric drivers.

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[52] DR 309, 659, 660, and 818

[53] DR 162 and 229

Exhibit VII-12
DPS and PSEG LI Model Comparison

Attribute	PSEG LI (2014-2016)	DPS	PSEG LI (2017)
Model Type	Econometric regression	Autoregression	Log regression
Number of Equations	9 1 Residential and 8 C/I	2 1 Residential and 1 C/I	2 1 Residential and 1 C/I
Residential Sector Dependent Variable	Annual Electric Use per Customer (U/C)	Log of Annual Electric Use per Customer	Log of Quarterly Electric Use per Customer
Residential Sector Independent Variables	Cooling Degree Days Median Real Home Price Real Customer Income Real Gross LI Product/Customer Employees/Customer Real Price of Electricity	Logs of: • Heating Degree Days • Cooling Degree Days • Real per capita income • Real price of electricity	Logs of: • Cooling Degree Days • Heating Degree Days • Median Real Household Income
C/I Sector Dependent Variable	For each sector: Annual Electric Use per Customer (U/C)	Log of Annual Electric Use per Customer	Log of Quarterly Electric Use per Customer
C/I Sector Independent Variable	Heating Degree Days Cooling Degree Days Real Customer Income Real Household Income Real Gross LI Product/Customer Households/Customer Employment/Customer Real Price of Electricity	Logs of: • Cooling Degree Days • Real per capita income • Real price of electricity	Logs of: • Cooling Degree Days • Heating Degree Days • Real Gross LI Product/Customer
Equation Format	$U/C_i=\beta_0+\beta_1X_{1i}+\beta_2X_{2i}+\beta_3X_{3i}+e_i$	$Log(U/C_i)= AR(1)+\beta_0Log(K)+\beta_1Log(X_{1i})+\beta_2Log(X_{2i})+\beta_3Log(X_{3i})+\beta_4Log(X_{4i})+e_i$	$Log(U/C_{i)}=\beta_0+\beta_1Log(X_{1i})+\beta_2Log(X_{2i})+\beta_3Log(X_{3i})+e_i$

Source: DR 650, 1015 and LIPA/PSEG LI Fact Verification.

C. SYSTEM PLANNING

Evaluative Criteria

- Do the infrastructure planning and engineering functions operate effectively?
- Does LIPA and PSEG LI 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 PSEG LI develop accurate system forecasts which are used in identifying infrastructure requirements?
- Are other load and infrastructure factors such as advanced metering, energy efficiency and REV initiatives given appropriate consideration in the planning process?
- Are the needs for major projects identified, developed and justified adequately?
- Are benefit/cost analyses and risk analysis considered in the decision-making process?
- Are planning for electric load and region-specific factors integrated into the overall business processes and strategies?

Findings and Conclusions

13. PSEG LI's Utility 2.0 is a meaningful and comprehensive plan that provides a roadmap for meeting LIPA's load commitments, REV initiatives, energy efficiency, renewables, and non-wires alternatives in a responsible manner.

- The Utility 2.0 Plan seeks to merge the traditional system wire and generation supply requirements with the customer experience. The Utility 2.0 Plan uses a combination of non-utility generation and storage technologies to reduce peak and defer infrastructure investments. The Utility 2.0 Plan not only identifies opportunities for DER but specifies the customer, meter, and IT requirement to advance the program.[54]

- The PSEG LI Utility 2.0 Plan is part of a broad effort that includes enhanced planning processes being developed by PSEG LI, and state-level initiatives such as the ongoing REV proceeding. Enhanced planning processes strive to meet system needs with a combination of customer solutions including: solar, battery storage, thermal storage, fuel cells, demand response, and load control programs. The plan effectively

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[54] DR 59

integrates load forecasting, transmission and distribution planning, supply planning, energy efficiency, demand reduction programs, and regulatory initiatives.[55]

- PSEG LI filed its first Utility 2.0 Plan with DPS in 2014, which LIPA adopted, and has updated it on an annual basis. For the 2014 Utility 2.0 Plan, PSEG LI's focus was implementing proven load relief technologies such as direct load control, behavioral energy efficiency, and geothermal heat pumps in its entire service territory to reduce system peak load. Consistent with NY REV objectives, PSEG LI modified its Utility 2.0 plan focus thereafter.

- For the last two years, Utility 2.0 annual updates have focused on technology neutral approaches to determine how select substation and T&D capital projects can be deferred by deploying load relief measures.

  - PSEG LI has now established an internal review process to determine which capital projects are suitable for load relief or load support alternatives while still meeting the timeline and cost considerations.
  - PSEG LI identifies the system need, prepares a Request for Proposal (RFP), and allows the market to determine the best solution.

14. PSEG LI's Planning and Engineering organizations have an effective process for determining infrastructure needs.

- Planning is responsible for the development of the five-year and ten-year system plan. The five-year and ten-year system plan process requires evaluation of projects as part of a potential Utility 2.0 solution. The purpose of the plan is to identify the major capital projects required to maintain service and improve reliability. The recommended system improvements consider reliability, performance and engineering feasibility.[56]

- Both the transmission planning and distribution planning organizations conduct annual studies to model current and future system behavior based operational and weather situations.[57]

- NorthStar reviewed the transmission planning studies conducted during 2016 and found PSEG LI has performed studies required to comply with NERC, Northeast Power Coordination Council, New York State Reliability Council, and PSEG LI transmission planning criteria. **Exhibit VII-13** provides a list of the studies, the model or software used to complete the study, and its purpose.

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[55] DR 59 and http://www3.dps.ny.gov/W/PSCWeb.nsf/All/A4F227628F73D62F85257F57006320E3?OpenDocument

[56] DR 59

[57] DR 238

Exhibit VII-13
PSEG LI Transmission Planning Studies

Study	Software System	Purpose
NYISO Summer Operating Study (PSEG LI supports the NYISO- it does not author the study)	PSS/E	Identify power transfer limits in the New York Control Area (NYCA) during upcoming peak summer season
NYISO Winter Operating (PSEG LI supports the NYISO – it does not author the study)	PSS/E	Identify power transfer limits in the NYCA during upcoming peak winter season
LIPA Summer Operating Study	PSS/E ASPEN TARA Python PI	Identify power transfer limits in Zone K during upcoming peak summer season - Establish operations horizons - Address specific Transmission Operations (TOP) requirements
LIPA Winter Operating Study		Identify power transfer limits in the NYCA during upcoming peak winter season - Establish operations horizons - Address specific TOP requirements
Local Transmission Plan		Details of transmission planning criteria, models, and local area development
FERC 715 Submission	PSS/E, PSSMOD, ASPEN, TARA, Python, PI	Submission of transmission data to FERC and NYISO
GR-3 Gas Burn	PSS/E	Determine limitation on Northport gas burn
PSEG LI Transmission Planning Criteria Document	MS Office	Ensure criteria changes are updated
LIPA TPL Planning Assessment	PSS/E, TARA, ASPEN	NERC TPL-001-4 and Facilities Design Construction and Maintenance (FAC)-014
FAC-014 Planning Horizon	PSS/E, TARA	Requirements of FAC-014, Req #4
BES Transmission Project SIS	PSS/E, TARA, ASPEN	Requirements of FAC-002
BES Buses Short Circuit Study	ASPEN	Requirements of NERC Protections and Control (PRC)-002
NYISO Interconnection Process	PSS/E, ASPEN, TARA	Conduct studies as needed for impact on transmission system due to potential generation interconnections
NYISO Comprehensive System Planning Process	PSS/E and ASPEN	Identify system adequacy
NYISO Fault Current Assessment	ASPEN	Identification of changes in fault current and associated equipment limitations
NYISO Area Transmission Review	PSS/E and ASPEN	Not applicable in 2016 Support NYISO in this review

Source: DR 62, 238 and 925.

- NorthStar reviewed the distribution planning studies conducted during 2016 and found PSEG LI has performed studies necessary to identify system growth constraints. **Exhibit VII-14** provides a list of the studies, the model or software used to complete the study, and its purpose.

Exhibit VII-14
Distribution Planning Studies

Study	Software System	Purpose
Summer Load Forecast – Distribution Substations and Circuits	ALF and PI	Develop forecast loads and system limitations on transformer banks and distribution feeders during the summer peak season.
Winter Load Forecast – Distribution Substations and Circuits	ALF and PI	Develop forecast loads and system limitations on transformer banks and distribution feeders during the winter peak season.
Distribution Load Transfers	CYME and ALF	Develop of operational instructions for the rearrangement of distribution loads.

Source: DR 62, 238 and 925.

- After completion of the planning studies, Planning develops potential system solutions where load serving and reliability issues are forecast to occur. Transmission and distribution planning evaluates the potential solutions and develops:

  - One-line diagram – a drawing of the system and necessary modifications.
  - Project Justification Document (PJD) – a document outlining the details of the project, the necessity, the need date, preliminary estimates, and alternatives analysis.
  - Five- and Ten-Year Transmission and Distribution Plan – a formal document outlining the major capital investment required to maintain system reliability.

15. PSEG LI has no evaluative criteria or measures to assess the effectiveness of its planning and engineering. Absent evaluative criteria or measures to assess effectiveness, NorthStar found the planning and engineering functions are reasonably effective.

- PSEG LI prepares expected work products, identifies system needs, and develops recommended system solutions.

- The statement of overall mission, goals and objectives by department/function make no mention of planning and engineering.[58]

- There are no regular managerial reports relating to planning and engineering effectiveness.[59]

- Engineering policies and procedures do not address performance, effectiveness or quality assurance.[60]

- The balanced scorecard has no direct metric that correlates to planning and one defined Tier 2 metric modestly relates to engineering effectiveness: Capital project

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[58] DR 3

[59] DR 5

[60] DR 62

performance measures the number of "engineering complete" milestones met based on a yearly plan.[61]

- There are no measures of engineering quality. Reliability metrics such as SAIFI and CAIDI are the only metrics that evaluate system health. Planning and engineering are too far removed from factors that most influence these metrics such as vegetation management.[62]
- NorthStar reviewed T&D planning materials from 2014 to the present and found no major change in functions, work products, or operations. The T&D planning functions are consistent with operations seen at other utilities. The work products are timely and well-supported. Planning functions include:
    - Determination of planning criteria
    - Data collection and specification of assumptions
    - Determination of study methodologies
    - Model specification and update
    - Evaluation of studies
    - Recommendation of system solutions.[63]

16. PSEG LI is developing an asset management function. A full discussion of asset management and preventive maintenance is found in Chapter VIII.

- PSEG LI recently created an asset management function to improve operational reliability and maintenance decision-making.[64] In late 2016, organizational changes were made to formally establish an Asset Strategy group containing specific asset subject matter expert positions. The purpose of this group is to provide governance and guidance to the transmission and distribution operations' organizations so that asset decisions (e.g., decisions to repair or replace, activity timing and maintenance practices) are made more consistently and with a strengthened business view. PSEG LI Asset Strategy continued to identify and add asset programs ("asset classes") during 2017.
- PSEG LI's development of new technologies such as its Centralized Maintenance Management System (CMMS), allows PSEG LI to leverage asset health data more effectively/efficiently. Better asset information is leading to improved maintenance decisions, schedule/plans and improved decision making regarding asset life. Other tools, such as a recent development of a modeling technology that analyzes asset life cycle for distribution assets, allows for better visibility to where assets are aging and require investment to maintain system performance.

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[61] DR 871
[62] DR 18 and 411
[63] DR 59
[64] DR 65 and 374

- In 2015, PSEG LI distributed a “Repair Versus Replace Decisions for LIPA T&D Assets” guidance document.[65] The document highlights the approach to be taken with regard to repair versus replace decisions specific to inside plant (most substation equipment) and outside plant (generally T&D equipment located outside the substation) assets.

- Improved reliability and extended life expectancy can be achieved by monitoring key T&D system equipment such as station transformers and breakers. For example, breakers that operate more frequently will degrade in performance and are more likely to fail in service. Maintaining these high operation units more frequently can extend their life prior to failure. Additionally, station transformers can be monitored for oil quality and moisture content and trending these variables will trigger increased maintenance or monitoring and eventually may drive a replacement prior to failure.

- Age alone is never the reason to retire an asset. Monitoring the results of inspection and testing programs along with failure history helps prioritize equipment replacements.

17. PSEG LI integrates plans for electric load and region-specific factors into overall processes and strategies for meeting infrastructure needs.

- Infrastructure needs are identified at the system level, individual load pocket level (18), distribution substation transformer level (368), and individual feeder level (1,089).[66]

- PSEG LI’s first step toward addressing infrastructure needs is the development of winter and summer operating studies as shown in Exhibit VII-13 to identify potential load transfers that would minimize immediate system needs.[67]

- When system needs are identified, PSEG LI has a process for recommending system solutions:

    - Development of traditional system solutions
    - Development of estimates of traditional solutions
    - Consideration of non-traditional solutions including:

        - Demand response/dynamic load relief
        - Energy efficiency
        - Advanced metering
        - Self-generation
        - Distributive energy resources.[68]

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[65] DR 65 Attachment 1
[66] DR 59, 238 and 868
[67] DR 238 Attachment 35
[68] DR 59

- LIPA's Utility 2.0 Plan provides a system view of potential DER applications to address system load growth. The plan is based on:
    - System initiatives including AMI
    - Revenue impacts
    - Known system capacity needs [69]
- PSEG LI studies and reports the accuracy of system level forecasts in monthly sales variance reports to PSEG LI and LIPA management.[70]
- PSEG LI does not prepare summary level forecast accuracy reports for PSEG LI or LIPA management on the substations, transformer banks, and feeders.[71]
    - PSEG LI develops transformer and feeder demand forecasts for a three-year horizon. The forecast is based on historical load modified for forecast system load, lump load additions, and distributed generation. The transformer bank forecasts are aggregated to produce substation forecasts. The transformer bank and feeder forecasts are provided annually as system planning studies.[72]
    - Each year, PSEG LI Distribution Planning reviews the forecast to actual demand variances. Differences are identified, and causes determined. Typical causes include load shifting, operational changes, equipment failure, and unforeseen loss of large customers.
    - The substation, transformer bank, and feeder forecasts are developed for two primary users:
        - Distribution Planning
        - Distribution System Operations.[73]
- In its 2016 DSIP Guidance Order, the DPS required utilities to provide substation level forecasts to energy marketers in order to identify areas for potential REV solutions. PSEG LI stated that at the present time, a substation level forecast is not available to the public and PSEG LI is not subject to April 2016 DSIP Guidance Order. This aspect of the DSIP function would follow a Utility 2.0 filing if approved by LIPA.[74]

18. PSEG LI properly coordinates and solicits potential DER opportunities.

- Infrastructure needs are identified through transmission and distribution studies. System needs are evaluated from a technical and financial perspective to determine a

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[69] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B2A0EA4D5-19C8-47FC-85BF-106857629FC0%7D

[70] DR 236

[71] DR 1018

[72] DR 236

[73] DR 1018

[74] DR 1018

cost effective solution. Solutions may include non-capital options such as operational and load transfer considerations and non-traditional capital solutions such as DER.[75]

- DER may be used to alleviate transmission and distribution capacity constraints. DER opportunities are referred to PSEG LI Power Markets for evaluation including feasibility, technical constraints and timing limitations.

- DER opportunities are evaluated alongside traditional utility solutions. If the traditional and DER solutions offer comparable ratepayer benefits and meet system reliability needs, PSEG LI will select the DER solution. The decision of when to pursue a non-traditional solution is described in Conclusion 19 and **Exhibit VII-15**.[76]

- Based on the decision matrix in **Exhibit VII-15**, PSEG LI has, thus far, identified three projects where DER participation is feasible.

  - South Fork – RFP issued in 2015 – See Conclusion 20
  - Yaphank – RFP to be issued in 2018
  - Smithtown – later withdrawn for operational reasons.[77]

19. PSEG LI properly considers alternative load and infrastructure factors such as advanced metering energy efficiency and REV initiatives in the planning process.

- PSEG LI evaluates alternatives to traditional T&D "wires" solutions in order to recommend the most appropriate and cost-effective projects to meet system needs.

  - Alternatives to conventional T&D wire type solutions can include temporary or permanent load transfers, substation modifications/additions, or REV-type solutions.
  - Each project or problem considers whether or not it would be practical to implement load reduction, battery storage or other REV-type initiatives as an alternative to the traditional solution. This review considers the percentage of load relief required or new load to be served, the timeframe in which it is needed, and the cost of the traditional project, among other considerations.
  - Viable projects are placed on a five-year project priority list, which is updated periodically based on revised load forecasts and area studies.[78]

- PSEG LI developed a decision matrix to identify projects that are viable candidates for REV-type solutions. This decision matrix, shown in **Exhibit VII-15,** guides PSESG LI's feasibility analysis of REV applications to satisfy Reliability and Planning design criteria violations.[79] PSEG LI stated that:

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[75] DR 64, IRs 105 and 106
[76] DR 59, 68 and 311
[77] DR 68 and IR 181
[78] DR 59
[79] DR 311

  - The decision making guideline establishes a collaborative and speedy framework for PSEG LI capital project review to determine if an alternative Load Relief project is feasible.[80]
  - While each capital project will contain some/many decision criteria which may look favorable (or unfavorable), this guideline provides a comprehensive decision making tool to ensure all key aspects of the potential capital projects are considered.[81]

- In its April 20, 2016 Order, the Commission ordered the state's investor-owned utilities to develop three screening criteria for the selection of Non-Wire Alternative (NWA) Projects: Project Type, Timeline and Cost. The matrix shown in **Exhibit VII-15** addresses all three criteria.[82]

- The use of emergency generators and/or power storage devices, when possible, is also considered to meet system contingency load situations. By addressing contingencies with short term solutions, longer term more economical projects or Utility 2.0 solutions can be pursued for a greater number of load growth situations.

- As part of the capital project planning process, PSEG LI evaluates REV solutions such as Smart Wire Technology for applicable major transmission projects.

  - Smart Wires provide devices that can be installed on transmission line structures and are used to "push" or "pull" power away from overloaded lines.
  - PSEG LI worked with Smart Wires to review planned transmission line upgrades over the next few years, and currently assessing the applicability of Smart Wire technology as an alternative to traditional reconductoring solutions.

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[80] DR 311

[81] DR 311

[82] NY DPS Case 14-M-0101 and Case 16-M-0411, Reforming the Energy Vision, Order on Distributed System Implementation Plan Filing (issued March 9, 2017)

Exhibit VII-15
PSEG LI - REV Decision Matrix

Load Relief Project as an Alternative to Conventional Capital Project Decision Criteria for selecting/eliminating Load Relief Projects

Load Relief – Alternative to T&D Project	Ideal	Possible	Not Recommended
Review and make Recommendations regarding Capital or Load Relief alternative project	T&D Planning to advise Energy Efficiency and Renewables (EERE) to initiate alternative Load Relief Project	T&D Planning and EERE to review project requirements and load profile – then make feasibility decision	No Further Analysis Needed – Follow traditional capital project process
Critical Considerations			
Load Relief Required as a percent of total load	<5% Expect	<5% Feeders 5-20% Group of Substations Likely to require batteries	>5% Feeders >20% Group of Substations
Load Relief requirement timeline	>3 years	2-3 years	Less than 2 years
Exposure to load left unserved	No	No	Yes
Capital project costs	>$10M Typically	$2M-$10M Typically	<$2M
Load relief required for substation group, substation or feeder levels	Wider-load are or substation group as a whole	A few substations in a group, non-specific at feeder levels	Multiple Specific Feeders and Substation
Other Considerations			
Residential Customer load as a % of total load	<40%	40-60%	>60%
Load Relief Required (hours per event)	<3 hours	3-8 hours	>8 hours
Number of Demand Reduction/Demand Load Control events per year	4	8-12	>12
Benefit of partial deferment – 1 to 2 years (rather to more a traditional 4 years or longer)	Yes	Yes	Minimal or None

Source: DR 311.

20. **PSEG LI Transmission Planning and T&D Engineering are presently collaborating with Smart Wires to assess the feasibility of Smart Wire technology for the Lake Success/Stewart Manor/Whiteside 69kV transmission line project by considering a compact deployment of the Smart Wires technology right at the Whiteside substation.[83] PSEG LI issues RFPs and RFIs to seek REV solutions to address some of the major load pocket growth or to meet regulatory requirements.**

- When timing of new load permits the solicitation of distributed generation solutions or load reduction opportunities, these are pursued though a competitive process.[84]

- At the time of the audit, PSEG LI was working to develop an RFP for REV solutions for the Yaphank load area. It is anticipated that a technology neutral RFP will be issued in early 2018 soliciting bids for cost effective "non-wires" solutions for the Yaphank area, unless it is determined that responses to Feed-In Tariff (FIT) IV will meet the need (See **Chapter XIV - Fuel and Purchased Power** for discussion of FIT IV).

    - In June 2015, PSEG LI issued a Request for Information (RFI) requesting information from qualified and experienced vendors with the capability to deliver REV solutions in five load areas with MW relief requirements.
    - Using the technology options offered in the RFI and utility industry experience regarding the potentials of these technologies, PSEG LI performed financial analysis comparing traditional capital solutions to REV solutions.
    - PSEG LI's financial analysis resulted in recommending the issuance of a REV RFP for two of the load areas – Smithtown and Yaphank. However, follow-on operational studies indicated a reduction in forecast load growth in Smithtown and the location was removed from consideration. PSEG LI issued RFPs for REV solutions to address the need for major transmission expansion to address load growth and/or regulatory requirements in South Fork and in Western Nassau.
    - In the South Fork and Western Nassau RFP processes, PSEG LI performed a detailed cost benefit analysis to determine the best solution to satisfy system requirements.
    - For South Fork, there were about 10 portfolios evaluated, with the selected portfolio being a combination of solicited resources (wind, batteries, and load reduction) and deferred transmission.
    - For the Western Nassau, it was determined that the solicited resources were much less cost effective than the proposed transmission solution. As such, PSEG LI decided to discontinue the evaluation process and proceed with the transmission plan.

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[83] DR 59

[84] DR 68

21. **PSEG LI adequately identifies, develops and justifies the need for major projects. PSEG LI however is limited in its ability to thoroughly develop alternatives analyses.**

- PSEG LI alternative analyses are limited by the accuracy of its estimating of project costs. Decisions based on inflated or deflated cost estimates result in selection of system solutions that will not yield the most value to LIPA. A more detailed discussion of cost estimating is found in **Chapter IX – Program and Project Planning and Management**.

- PSEG LI diligently performs the necessary system studies, including forecasts, voltage and thermal studies and operations analyses.

- In general, PSEG LI considers alternatives, including REV initiatives, when infrastructure needs are identified. **Exhibit VII-16** provides examples of major projects and the alternatives considered.

- Numerous REV alternative solutions were not selected due to insufficient time. PSEG LI chose traditional wire solutions. The DPS acknowledges recent utility experience timelines of 60 months in obtaining NWA solutions. Overlapping the 5-year timeline with a current system need would have required starting an NWA solution in as early as 2011. The DPS order for DSIP plans was issued in April 2016.[85] It is anticipated the PSEG LI will evaluate more NWA opportunities on a cost-benefit basis going forward as the NWA timeline will align with the planning horizon.

Exhibit VII-16
Major Projects and Alternatives Considered

Project	Alternatives [Note 1]	Basis of Selection
Deer Park C&R Reconductoring	1. Reconductor ($960,000) 2. New Feeder ($3M) 3. REV – demand reduction	There was insufficient time to complete a demand reduction program so least cost alternative was chosen.
Amagansett-East Hampton	1. New substation equipment and upgrade of voltage (no estimate) 2. New Underground Cable 3. REV– New generator	There was insufficient time to complete an RFP and construct generation. It was estimated the new underground cable would be much more expensive.
Cedarhurst Upgrade	1. Upgrade ($7M) 2. New Banks at Woodmere ($24M) 3. New Substation ($23M) 4. REV - DER	There was insufficient time to complete a DER project. Least cost option was selected.

Note 1: Alternative 1 was the selected alternative.

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[85] DPS Case 14-M-0101 and Case 16-M-0411, Reforming the Energy Vision, Order on Distributed System Implementation Plan Filing (issued March 9, 2017)

Source: DR 669.

- PSEG LI's Transmission and Distribution Planning organization does not develop estimates. Estimating is discussed in detail in C**hapter IX - Program and Project Planning and Management**. In summary:

  - Estimates were historically developed by the appropriate design engineering function.
  - PSEG LI has recently instituted an estimating function within its project management organization.
  - Quality data supporting engineering estimates was not available. PSEG LI has recently invested in the SAGE estimating software system. It will take time to populate the model.
  - Alternative analyses are based on ball-park estimates and limited project scope.[86]

22. PSEG LI does not perform detailed cost/benefit analyses in the selection of system solutions; PSEG LI addresses risk in only two ways, feasibility and project scoring.

- Utility infrastructure investments are driven largely by reliability requirements. Typically, the lowest cost option is selected. Traditional cost/benefit analysis has limited application.

- Feasibility – PSEG LI evaluates potential system solutions from both technical and financial feasibility perspectives. System solutions are estimated (as discussed in **Chapter IX – Program and Project Planning and Management**) and reviewed by engineering for technical feasibility. PSEG LI project justification documents demonstrate this process on large projects. The goal of planning's feasibility review is to reduce the risk associate with non-completion and stranding of capital assets.[87]

- Project Scoring – Prior to 2017, PSEG LI addressed four aspects to risk in its project scoring exercise:

  - Regulatory compliance/requirements
  - Customer service
  - Financial performance
  - Technical performance

  This aspect of risk quantifies the effect of not funding a specific project against other projects.[88] In 2017, PSEG LI implemented its spend optimization suite (SOS) for scoring projects. The four aspects to risk have been expanded and included with other considerations to include: Green, People, Economic, and Safe and Reliable. A full discussion of SOS is found in **Chapter IX – Program and Project Planning and Management**.

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[86] IR 104, 105, 106 and 200; DR 568, 618

[87] DR 239, IR 106

[88] DR 239, IR 100-106

- Transmission planning develops cost/benefit analysis for projects when a thermal overload occurs. PSEG LI has a three-part analysis:

  - Present worth-analysis
  - Benefit/Cost ratio
  - First year rate impacts.[89]

D. RECOMMENDATIONS

1. Develop evaluative criteria or other measures to assess the effectiveness of the planning process. Effectiveness should be measured based on specifics, for example:

   - Number and timeliness of system studies

   - Timeliness of development of PJDs

   - Quality of PJDs (e.g., do they contain all requisite information?)

   - Relative accuracy of conceptual level estimates

2. Perform detailed cost-benefit analyses consistent with Transmission Planning's analyses for projects related to thermal overload.

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[89] DR 59, 239; IRs100-106

VIII. TRANSMISSION AND DISTRIBUTION

This chapter provides the results of NorthStar's review of PSEG LI's operation of LIPA's transmission and distribution (T&D) system. The review included an assessment of policies, procedures, practices, and system performance as well as a review of LIPA's oversight. The audit of T&D focused on:

- Reliability
- Preventive Maintenance
- Repair/Replace and Reactive/Corrective Maintenance
- Outage Management – System Improvements and Performance.

A. BACKGROUND

PSEG LI maintains and operates a power delivery system that includes: bulk transmission, sub-transmission, substations, and a distribution system serving all of Long Island and portions of Queens.

LIPA's transmission system is approximately 62 percent overhead lines and 22 percent underground cables. The remaining 16 percent is mixed overhead and underground infrastructure. LIPA has 186 substations (9 Generation, 28 Transmission, and 149 Distribution) that provide switching and voltage conversion at both the transmission and distribution levels.[1]

The primary distribution system is approximately 66 percent overhead while the 120/240V secondary system is 75 percent overhead. Primary distribution circuits, operating at 4 kV and 13 kV, originate at circuit breakers connected to the distribution substations. 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 (ASUs), automatic circuit reclosers (ACRs), ground-operated load break switches and stick-operated load break disconnects. The distribution system also has a small number of low voltage secondary network services which serve fewer than 6,000 customers.[2]

The Amended and Restated Operating Services Agreement (A&R OSA) dated December 31, 2013, establishes PSEG LI as the service provider to furnish operating and maintenance services for LIPA's system. PSEG LI's T&D organization is consolidated under the Vice President of Electric Operations, who reports directly to the President and Chief Operating Officer (COO) of PSEG LI. **Exhibit VIII-1** provides the organizational structure as of August 2017. Dotted lines represent an informal reporting relationship with other PSEG LI and PSE&G organizations that support Electric Operations.

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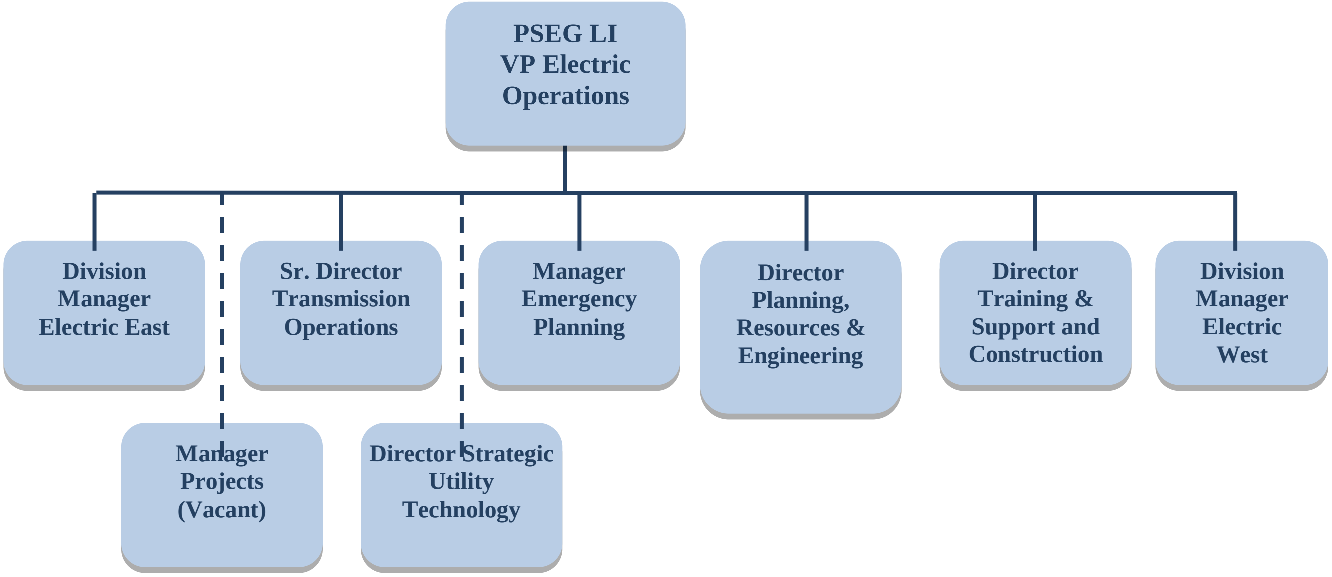
[1] DR 856

[2] DR 952

Exhibit VIII-1
PSEG LI T&D Operations



Source: DR 830.

Transmission Operations is responsible for the operation and maintenance of the transmission system throughout LIPA's service territory. The Electric East and Electric West Divisions are responsible for the operation and maintenance of LIPA's distribution system and substations. Each Division is organized in the same manner, with five groups:

- Distribution Engineering and Resources
- Overhead (OH) and Underground (UG) - 2 groups in each division
- Substation Operations
- Distribution Operations.

LIPA's service territory was traditionally divided into four districts as shown in **Exhibit VIII-2**. The four operating districts were supported by centralized support services such as engineering, substation and relay operations, and distribution system operations. In August 2017, PSEG LI reorganized into two divisions, East and West, splitting at the Nassau County-Suffolk County line. Each division has two overhead and underground groups aligned with the historical four districts. Each new region operates autonomously with integrated engineering and other support services.[3]

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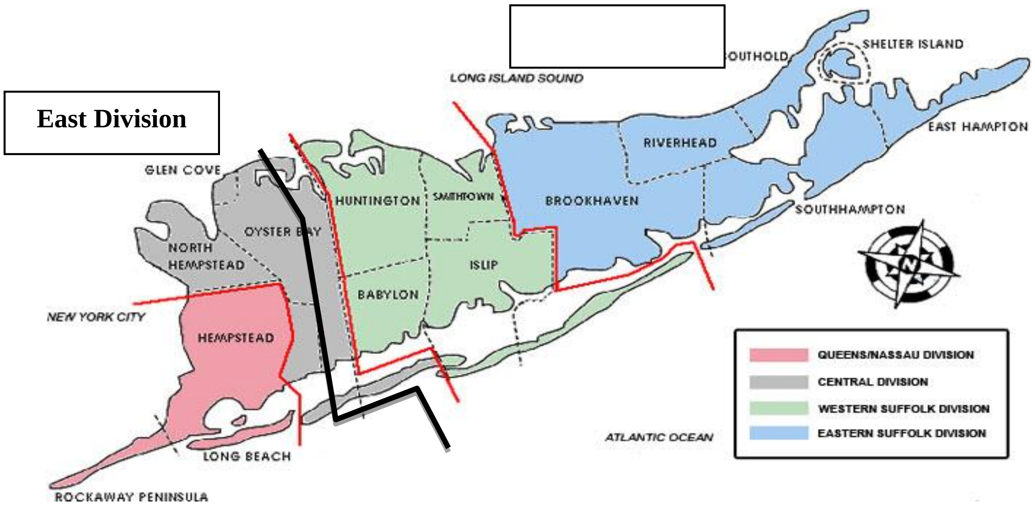
[3] DR 830

Exhibit VIII-2
Service Territory Map



Source: https://www.psegliny.com/page.cfm/AboutUs/Territory.

Western Region	
Old Queens/Nassau District Serves approximately 212,903 customers 100 square miles of service territory 978 miles of primary overhead wire 3,054 miles of secondary overhead wire 238 miles of primary underground cable 369 miles of secondary underground cable 47,607 utility poles	**Old Central District** Serves approximately 291,862 customers 200 square miles of service territory 2,370 miles of primary overhead wire 5,735 miles of secondary overhead wire 755 miles of primary underground cable 1,031 miles of secondary underground cable 93,864 utility poles
Eastern Region	
Old Western Suffolk District Serves approximately 322,616 customers 320 square miles of service territory 2,847 miles of primary overhead wire 6,215 miles of secondary overhead wire 2,295 miles of primary underground cable 3,219 miles of secondary underground cable 97,882 utility poles	**Old Eastern Suffolk District** Serves approximately 294,630 customers 610 square miles of service territory 2,562 miles of primary overhead wire 6,686 miles of secondary overhead wire 1,190 miles of primary underground cable 1,917 miles of secondary underground cable 101,972 utility poles

Source: DR 860.

Reliability

System reliability is a measure of the effectiveness of T&D operations and maintenance (O&M) programs. System reliability can be measured by several industry standard metrics. The three most common reliability indices measure average outage frequency, outage duration and customer outage length. PSEG LI reports these standard indicators on PSEG LI's monthly Balanced Scorecard: System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), and System Average Interruption Duration Index (SAIDI). PSEG LI reports outage data to the New York Department of Public Service (DPS) in order for the DPS to independently calculate the reliability indices.

For a full discussion of the Balanced Scorecard and Performance Metrics see **Chapter XIII - Performance Management**.

PSEG LI replaced LIPA's legacy Computer Assisted Restoration of Electric Service (CARES) OMS and installed the CGI Group Inc. (CGI) OMS system in August 2014. The new OMS system provides contemporaneous outage information permitting the capture of outage events. The functions of the OMS include:

- Prediction of location of outage and equipment (e.g., breaker, switch, fuse) that may have operated.
- Prioritization of restoration by identifying most critical outages.
- Reporting of outage information – extent and number of customers affected.
- Calculation of restoration time.
- Calculation of crews necessary to restore outages.
- Provision of real-time information to customers.
- Archiving of relevant outage information including number of customers affected, length of time of outage, and cause.

The CGI OMS is a new technology that operates differently from the CARES OMS.

- The CARES OMS was initiated by customer calls. Affected customers were estimated by a process called "polygoning," where an outage pattern is developed and customers are grouped based on the pattern. Polygoning is a manual process that is dependent on system maps, the discretion of the dispatcher, and correlation between the maps and number of customers.[4] Data for reliability calculations are based on the manual input from trouble tickets.

- The CGI OMS is initiated by both customer calls and LIPA's SCADA system. Affected customers are determined by a software system called Pragma. Pragma determines affected customers using a "stepping" methodology, where each SCADA operation and customer call interacts with the GIS to provide correlation to cause of outage and number of affected customers. Data for reliability calculations is populated from the CGI system based on the magnitude of the outage determined by Pragma.[5]

B. EVALUATIVE CRITERIA

The Transmission and Distribution audit followed the list of baseline evaluative criteria provided by the DPS and an overall assessment of the effectiveness of the Authority's and Service Provider's operations management.[6]

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[4] Matter 12-00314, The Comprehensive Management and Operations Audit of the Long Island Power Authority Final Report by NorthStar Consulting Group dated September 13, 2013.

[5] DR 822

[6] DPS RFP and Bidder's Package for Matter 16-01248, August 5, 2016

Reliability

- Does LIPA/PSEG LI have meaningful SAIFI, CAIDI and SAIDI goals and are they met?
- Does LIPA/PSEG LI make effective use of mobile workforce tools? (Addressed in **Chapter X - Work Management and Outside Services**)
- Does PSEG LI achieve and maintain adequate levels of system reliability?
- Does PSEG LI appropriately monitor and respond to potential reliability issues?
- Does PSEG LI analyze worst performing circuits and take steps to address issues?

Preventive Maintenance

- Is preventive maintenance properly scheduled, performed, and noted?
- Are trend analyses maintained?
- 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?
- Is PSEG LI's equipment inspection and testing schedules consistent with accepted good utility industry practice?
- Has PSEG LI incorporated up-to-date processes and tools for monitoring, analyzing and maintaining LIPA's 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 at appropriate cost levels?
- Is LIPA/PSEG LI appropriately involved in establishing preventive maintenance standards and requirements?
- Does LIPA/PSEG LI 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?

Repair/Replace and Reactive/Corrective Maintenance

- Are adequate cost/benefit analyses performed to assist in the repair/replace decision-making?

Outage Management – System Improvements and Performance

- Are outage lessons learned reflected in modifications to disaster or emergency restoration plans, training, staffing, system planning or response requirements?
- Has there been effective improvements of the OMS since the transition from the Management Services Agreement (MSA) to the A&R OSA under PSEG LI?
- Is the OMS data captured reliable and timely?

- Do storm events or other reliability problems result in lessons learned and changes to the existing system or processes?
- Does LIPA/PSEG LI have a comprehensive disaster or emergency restoration plan, and is it periodically revised, and appropriately communicated with effective training?

C. FINDINGS AND CONCLUSIONS

Reliability

1. PSEG LI uses and reports meaningful measures of reliability which are industry standard and called for in the A&R OSA.

- Reliability performance metrics and methodology are defined in the A&R OSA dated December 31, 2013.[7]

- PSEG LI calculates system reliability consistent with industry accepted methods and New York investor-owned utilities that are required to report SAIFI and CAIDI to the DPS. In addition, SAIDI, another standard reliability metric, is a PSEG LI Tier One performance metric.[8]

  - SAIFI (number times average customers is interrupted in a year) is calculated as:

    $$\text{SAIFI} = \frac{\Sigma \text{ Customers Interrupted}}{\#\text{ Active Customers}}$$

  - SAIDI (number of minutes the average customer is interrupted in a year) is calculated as:

    $$\text{SAIDI} = \frac{\Sigma \text{ Customers Interrupted x Outage Duration in Minutes}}{\#\text{ Active Customers}}$$

  - CAIDI (Average length of an outage) is calculated as:

    $$\text{CAIDI} = \frac{\Sigma \text{ Customers Interrupted x Outage Duration in Minutes}}{\Sigma \text{ Customers Interrupted}}$$[9]

- A major storm is a period of adverse weather during which service interruptions affect at least 10 percent of the customers in an operating area and/or result in customers being without electric service for durations of at least 24 hours.[10] Reliability indices are determined for both the inclusion and exclusion of major storms. All reliability indices discussed and reported in this chapter exclude major storms (unless specifically stated otherwise).

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[7] DR 4

[8] SAIFI and CAIDI are also Tier One metrics, DR 134.

[9] IEEE Standard 1366, http://standards.ieee.org/findstds/standard/1366-2012.html

[10] 16 NYCRR Part 97

2. **PSEG LI has maintained high levels of reliability when compared to NY electric utilities. LIPA customers have the second lowest number of outages annually and the shortest outage durations in New York.**

   - Reliability metrics are, in part, the result of circumstances unique to a service territory including: system design, load density, geographical terrain, and weather patterns. LIPA benefits from high load density, a primarily suburban service area, and moderate winters.

   - **Exhibit VIII-3** shows the five-year SAIFI and CAIDI average (excluding major storms) for New York's electric utilities.

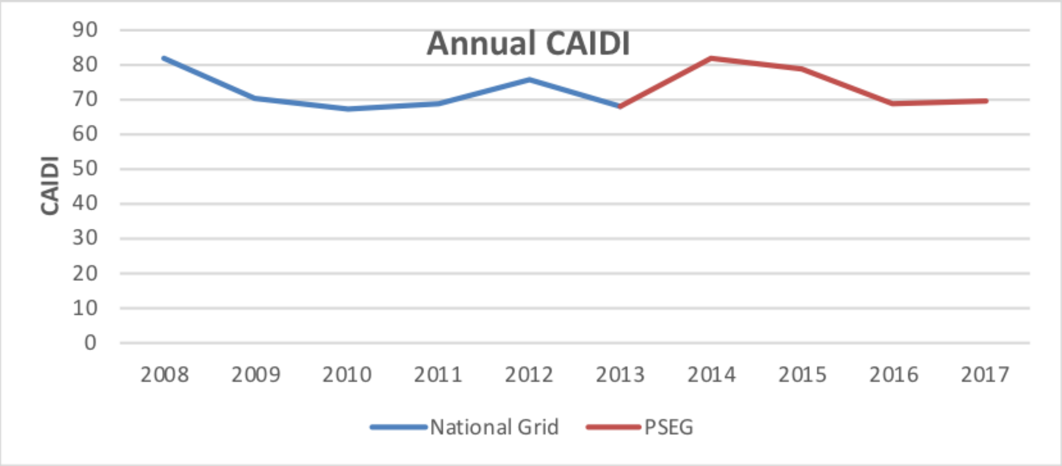
Exhibit VIII-3
New York Utility SAIFI and CAIDI Metrics [Note 1]
Five-Year Average (2012-2016)

Utility	SAIFI	CAIDI
Consolidated Edison (Radial System)	0.37	116.4
National Grid	0.98	120.0
New York State Electric and Gas	1.09	118.8
Rochester Gas and Electric	0.71	107.4
Central Hudson Gas and Electric	1.18	136.2
Orange & Rockland	1.00	108.6
Long Island Power Authority	0.81	73.8
Statewide (without Consolidated Edison)	0.95	109.8

Note 1: Excludes major storms and outages greater than 24 hours.
Source: NYS DPS Annual Reliability Report 2016.

   - PSEG LI has consistently achieved its annual CAIDI target. The average duration of interruptions remained generally constant over the past ten years. **Exhibit VIII-4** provides the ten-year CAIDI trend.

Exhibit VIII-4
LIPA Annual CAIDI Performance Trend
(minutes/customer)



Source: NYS DPS Annual Reliability Report 2007 through 2016 and DR 991.

3. System reliability performance goals have been relaxed since the 2013 targets.

- As shown in **Exhibit VIII-5** the targets represent poorer reliability than actual historical SAIDI, SAIFI and CAIDI performance, and less aggressive targets than used for National Grid.[11]

Exhibit VIII-5
Ten Year Actual and Target SAIFI, SAIDI and CAIDI
(Lower Values Indicate Better Reliability)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
SAIFI										
Actual	0.77	0.74	0.73	0.75	0.67	0.71	0.72	0.84	1.11	0.95
Pre-2014 Target	0.83	0.83	0.83	0.83	0.83	0.83				
PSEG LI Target							0.90	0.92	0.92	0.92
SAIDI										
Actual	63.0	51.6	48.6	51.6	50.6	47.9	59.1	65.7	75.5	65.8
Pre-2014 Target	55.5	55.5	55.5	55.5	55.5	55.5				
PSEG LI Target							66.2	68.5	68.5	68.5
CAIDI										
Actual	81.6	70.2	66.6	68.4	75.6	67.8	81.6	78.6	68.4	69.0
Pre-2014 Target	66.3	66.3	66.3	66.3	66.3	66.3				
PSEG LI Target							84.0	85.0	85.0	85.0

Source: DRs 18, NYS DPS Annual Reliability Report 2007 through 2016, and Matter 12-00314, The Comprehensive Management and Operations Audit of Long Island Power Authority Report by NorthStar Consulting Group dated September 13, 2013.

- The A&R OSA prescribes that the annual targets are to be calculated based on a ten-year average plus two standard deviations, which resulted in less aggressive goals. PSEG LI stated that the methodology was approved by both the LIPA Board of Trustees and the DPS. PSEG LI also stated that the new targets have been benchmarked to 1st quartile performance.[12] NorthStar believes that this methodology does not appear to promote continued performance improvement.

- According to PSEG LI, target revisions in 2015, were driven by several factors including the implementation of the new OMS and the introduction of the NRA policy.[13] NorthStar reviewed PSEG LI's rationale and assumptions for the changes, but could not independently justify the specific targets. The effect of PSEG LI's new OMS and revised operational procedures on SAIFI values cannot be confirmed or quantified with any certainty.

    - The CARES OMS and the CGI OMS never operated side-by-side. PSEG LI simulated historical outages on CGI and developed a statistical solution for

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[11] DR 18 and Matter No. 12-00314, The Comprehensive Management and Operations Audit of Long Island Power Authority Report by NorthStar Consulting Group dated September 13, 2013

[12] DR 4 and LIPA/PSEG LI Fact Verification

[13] DR 628 and 748

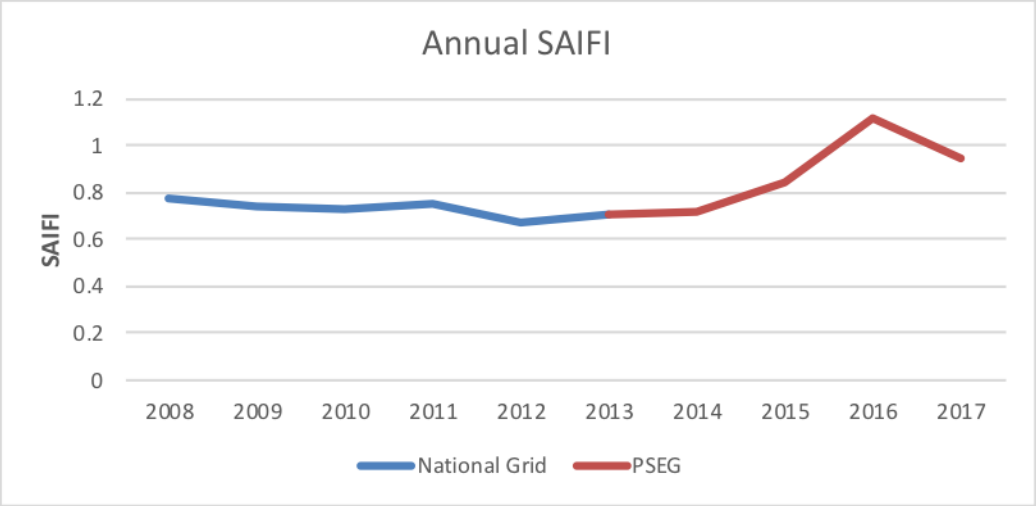
quantifying the differences. It was found that SAIFI would increase 1.6 percent due to the new OMS.[14]

- PSEG LI's reported SAIFI and CAIDI are correctly calculated based on OMS data and validated number of customers.[15]
- PSEG LI's independent audit conducted by a consulting firm during 2017, estimated the change in SAIFI to be 1.5 percent annually due to the new OMS and operational changes.[16]

4. PSEG LI has seen a recent trend of increasing SAIFI (decreased reliability). The increase in SAIFI is partially attributable to numerous operational changes.

- PSEG LI's SAIFI performance has improved during 2017.
- **Exhibit VIII-6** provides the ten year SAIFI trend.

Exhibit VIII-6
LIPA System Annual SAIFI Performance Trend



Source: NYDPS Annual Reliability Report 2007 through 2015 and DR 991.

- PSEG LI states that its SAIFI performance has been affected by numerous system and operational changes since 2013 that have contributed to the increase in SAIFI (lower reliability), including:
  - Installation of a new OMS – PSEG LI contends that the new OMS provides better customer counts as opposed to the old CARES system. The SAIFI index prior to the new OMS was based on a manual process. The determination of the number of customers was a subjective process that was only as accurate as the polygons were drawn and the maps used.

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[14] DR 926
[15] DR 928
[16] DR 561 Attachment 1, Page 28

- Increased intentional outages for system improvement programs such as asset management and maintenance activities. (See Conclusion 5 – Intentional Outages)
- Increased outages due to multiple operations of equipment such as reclosers and circuit breakers during outage restoration. Historically outages were reported by customers – generally one time per event. Outages are now reported to the OMS by the SCADA system as well as by customers. The SCADA system reports each intermittent outage during a restoration event.
- New operational procedures including the implementation of a non-reclosing assurance policy (NRA) on automatic reclosing of circuit breakers.[17]

5. PSEG LI's classification of outages as "intentional" is not a compelling reason for missing its SAIFI target.

- PSEG LI classifies some outages as "intentional." "Intentional" is not an industry accepted term. PSEG LI developed the term to classify two system conditions:

  - Prearranged and Planned – interruptions taken with advance notice to the customer.
  - Intentional – outages that are taken to safely clear a line as part of service restoration.[18]

- The NY DPS defines "prearranged outages" as:

> *"*7. *Prearranged* Under this heading, report interruptions resulting from actions deliberately taken by the utility upon advanced notice to the customers affected (prearranged). Deliberate interruptions (lasting at least five minutes) without prior notice to the customers affected shall be reported under the classifications most directly related to the reasons the outages were needed. They shall be considered part of a forced interruption when they take place during Emergency conditions to facilitate restoration."[19]

- NorthStar reviewed a sample of "intentional" outages and found nothing that would constitute emergency conditions. NorthStar also found that most of the restorations were consistent with normal business practices (i.e., there was an equipment failure PSEG LI appropriately monitors and responds quickly to potential reliability issues.

- In order to better understand outages causes and improve system reliability, PSEG LI has developed an extensive coding system for outage causes. Identification of outage causes permits further study to determine patterns or trends that could possibly impact reliability. Coded information includes:

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[17] DRs 628 and 748

[18] DR 881

[19] 16 NYCRR 97.5, http://www3.dps.ny.gov/N/nycrr16.nsf/364bc4db8005c8b48525702d004a1baf/36f87976a00f87d485256fc7004fd61a/$FILE/97.pdf

  - The affected system (e.g., substation, transmission, distribution mainline)
  - The voltage
  - The equipment
  - Number of customers affected
  - Event times (time of outage, time crew was dispatched, time service was restored)
  - The cause (e.g., vegetation, animal contact, equipment failure, motor vehicle)

- PSEG LI is in the process of implementing maintenance and asset management programs to increase system reliability, based in part on OMS data, including:

  - Identification of worst performing circuits
  - Multiple customer outage analysis
  - Circuit Improvement Program (CIP)
  - Residential underground cable replacement program
  - Substation breaker replacement program
  - Pole replacements
  - Distribution transformer replacement program
  - Federal Emergency Management Agency (FEMA) mainline hardening program
  - More aggressive vegetation management trim cycles
  - Infrared inspection program.[20]

- PSEG LI continues to employ a "worst performing circuit" program to identify and mitigate their impact on customers and reliability. PSEG LI identifies its worst performing circuits annually. A circuit is identified as a worst performer based on the number of interruptions normalized by the number of customers affected.[21] This measurement, similar in nature to SAIFI, permits prioritization based on the number of customer affected.

  - Only one circuit was on PSEG LI's worst performing circuits list for all three years, an indication that PSEG LI corrects system issues on a timely basis and addresses circuits that are problematic.[22]
  - PSEG LI has improved the reliability of certain circuits on the worst performing circuits list. Specific examples include:

    - Circuit 6Q667 was on the list in 2014. The circuit subsequently underwent complete tree trimming, FEMA storm hardening, two new automated sectionalizing switches, and rebuilding of mainline with stronger wire and bigger poles.
    - Circuit 8J684 was on the list in 2015 and 2016. The circuit underwent tree trimming, FEMA storm hardening, and mainline rebuilding. Patrols of the circuit discovered two hot spots that are scheduled for mitigation in 2017.
    - Circuit 2H579 was on the list in 2014. Improvements included new cable, new relays, new underground cable, FEMA storm hardening, automated

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[20] DRs 117, 120, 302, 303, 490, 663, and 664

[21] DR 117

[22] DR 117

sectionalizing switches, and mainline replacement. As part of the 2014 CIP, PSEG LI installed new transformers, poles, cross arms, surge arresters and fuses.[23]

Preventive Maintenance

6. Numerous PSEG LI organizational units provide comprehensive and effective support to the distribution, substation, and transmission system preventive maintenance mission.[24]

- Overhead/Underground (OH/UG) Lines – Performs underground transmission manhole inspections for high pressure fluid filled systems, maintenance repairs coming from annual infrared inspections of both distribution and transmission facilities, maintenance from any substandard conditions noted from annual transmission line patrols conducted by Operations, and maintenance repairs coming from Distribution Design inspections of distribution system circuits and pole replacements coming from pole health inspections.

- Distribution Operations – Performs inspection and maintenance on distribution system capacitor banks, inspection and maintenance on distribution system network transformers/protectors, inspection and maintenance on automatic throw-over switches.

- Distribution Automation – Coordinates annual inspection/check of operability of distribution system capacitor banks, ASUs, and ACRs.

- Meter Services – Performs maintenance on distribution system capacitor banks.

- Distribution Design – Performs periodic walk-down inspections of the distribution system identifying any substandard conditions.

- Vegetation Management – Oversees contractors performing the 4-year cycle for distribution and transmission tree trimming.

- Substation Maintenance - Performs inspection and maintenance on distribution system network transformers/protectors. Performs all preventive maintenance activities of equipment contained within LIPA substations (e.g., transformers, breakers, switchgear, battery sets, switches).

- Underground Lines – Performs all preventive maintenance of Underground transmission terminations within the substation confines.

- System Protection Operations – Performs all preventive maintenance activities relating to system protective relaying devices/schemes.

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[23] DRs 117 and 740

[24] DR 384, 910

7. LIPA does not provide significant input to PSEG LI regarding the preventive maintenance program and its oversight of PSEG LI preventive maintenance activities is minimal.

- LIPA stated that the A&R OSA assigns PSEG LI sole responsibility for the establishment and execution of the preventive maintenance program.[25]

- LIPA's oversight of preventive maintenance includes participation in the monthly Balanced Scorecard data review meetings and modification of Performance Incentive Metrics. LIPA Operations Oversight monitors the current PCall reported outages, loss of service notifications, and various SAS reports to identify operational issues.[26]

- LIPA reviewed the preventive maintenance programs proposed by PSEG LI as part of the 2015 rate case filing and provided testimony on the programs including tree trimming. Since that time, LIPA's oversight has involved assessing PSEG LI's compliance with the preventive maintenance programs.[27]

8. PSEG LI continues to improve processes and tools for analyzing and maintaining the electric system.

- Key T&D system equipment, such as station transformers and breakers are critical system components that require large capital investments and therefore warrant a rigorous preventive maintenance program.[28] Properly performed maintenance on these types of assets can significantly extend the life of system equipment. However, there are external influences that can significantly shorten the life of equipment such as:

    - Storm events
    - Temperature
    - Animal contact
    - System transients.

- PSEG LI has begun to use asset health analyses and reports as part of its Asset Management Program.[29] To date, equipment life expectancy has relied on many conceptual factors:

    - Historical performance of the asset
    - Health of the asset using available test data to evaluate condition
    - Cost of maintaining the asset
    - Reasonable life extension potential for the asset
    - Risk to safety of personnel, and reliability to the system, should the asset failure unexpectedly

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[25] DR 385

[26] LIPA/PSEG LI Fact Verification

[27] LIPA/PSEG LI Fact Verification

[28] DR 392 and 393

[29] DR 826 – No Response

  - Availability of suitable spare in the event of a failure.[30]

- PSEG LI's assumptions for life expectancy for key T&D equipment are as follows:[31]

  - From an accounting/financial perspective, key T&D assets have a depreciation life ranging from approximately 40 years to 70 years.
  - Asset classes do tend to have an average life but individual assets within the class vary in life based on manufacturer, technology, use (load, operations, etc.) and external conditions (soil conditions, environmental conditions, etc.)
  - Realizing that there are variations within asset class, PSEG LI recognizes the following life expectancies for the following asset classes:

    - Wood poles – 45 years
    - Pole top transformers – 35 years
    - Station power transformers – 45 years
    - Station circuit breakers – 45 years.

- In practice, the life expectancy of an asset is generally used only as a benchmark for future funding that may be required to maintain safe and reliable service.[32] Inspection and testing programs along with failure history guide PSEG LI equipment replacements. Age alone is not used to retire an asset.

- PSEG LI improves reliability and extended life expectancy by monitoring key T&D system equipment such as station transformers and breakers. For example, breakers that operate more frequently will degrade in performance and are more likely to fail in service. Maintaining these high-operation units more frequently may extend their life prior to failure. Additionally, station transformers can be monitored for oil quality and moisture content. Trending these variables can trigger increased maintenance or monitoring and eventually may drive a replacement prior to failure.[33]

- PSEG LI characterizes many preventive maintenance improvement programs as operational but more accurately they are in their infancy.

  - PSEG LI indicated that it "employs several reliability and maintenance programs that are intended to understand the general health condition of all T&D assets on LIPA's system."[34] However, when asked to describe the "3rd party data analytics program," the response provided was vague and indicated that "the program is a tool to be used in the near future by the Asset Management organization…"[35] When asked to provide the reports produced by this analytics program, none were provided.[36]

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[30] DR 392 and 393
[31] DR 552
[32] DR 552
[33] DR 550
[34] DR 393
[35] DR 907
[36] DR 908

  - The Black & Veatch Asset Management Plan dated April 5, 2017 states that "PSEG-LI has developed Asset Management Plans for each asset class within the Electric Distribution System listed below."[37] By using the past tense, the document implies that these Asset Management Plans existed as of the date of the document. However, no such Asset Management Plans were provided to NorthStar in response to a data request.
  - PSEG LI created an Asset Strategy group in late 2016 to provide increased support to the preventive maintenance programs. The group's mission is to perform periodic reviews of equipment performance, inspection results, and the costs associated with performing both preventive and corrective maintenance programs.[38]

    - PSEG LI launched the Computerized Maintenance Management System (CMMS) in 2016 to provide asset health data for analysis in determining whether assets require enhanced maintenance diagnostics and assist in replacement decisions. CMMS is currently operating and will be fully implemented in 2020.[39]
    - Asset Management and CMMS are modeled after PSE&G's successful programs.
    - SAP will continue to be used for inspection schedules as well as capturing the costs associated with the programs.
    - Improvements are anticipated in reduced capital and operating costs through more efficient utilization of resources and equipment, accelerated development and deployment of emerging technology and reduced funding and risk through investment prioritization.

- In interviews with NorthStar, LIPA and PSEG LI explained that the Asset Management Program is in its infancy. Although certain goals have been identified for the program, the program is not currently operating at full capacity.

9. PSEG LI has adjusted LIPA's traditional preventive maintenance practices based on PSE&G's experience in New Jersey.

- PSEG LI has modified the preventive and corrective maintenance programs, specifically within the inside and outside plant categories, by refining the cycles for each asset class to align with PSE&G, believed to be preferred industry practices.[40]

- **Exhibit VIII-7** provides a summary of the preventive maintenance cycles developed by Asset Management's System Reliability organization.[41]

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[37] DR 252: Consultant Asset Management Plan dated April 5, 2017

[38] DR 123

[39] DR 1005 Attachment 1

[40] DR 123

[41] DR 921

- The vegetation management program was advanced to a 4-year-cycle from a 5+ year-cycle.
- The pole inspection program was moved to a 10-year cycle. Previously, the program cycle frequency was undefined.

Exhibit VIII-7
PSEG LI Preventive Maintenance Frequency Adjustments

Description	Legacy Frequency	Current Frequency
Enhanced Inside Plant Maintenance Plans (Temporary Frequency Adjustments)		
Transformer Maintenance	8 Years	6 Years
Switchgear Maintenance	10 Years	6 Years
Switchgear Breaker Maintenance	8 Years	6 Years
Motorized Switch Maintenance	Undefined	6 Years
One Time Inside Plant Maintenance Activities		
Switchgear Roof Sealing	Undefined	One Time
Equipment Painting	Undefined	One Time
Animal Guarding of Equipment	Undefined	6 Years
Vegetation Clearing within Substations	Undefined	One Time
Other Inside Plant Maintenance Enhancements		
Increased Maintenance on relay communication equipment	Not Required	10 Years
Power Transformer Testing Enhancements		
Sweep frequency response analysis (SFRA)	Not Performed	6 years
Winding resistance testing	Not performed	6 years
Watts loss testing of switchgear busses	Not performed	6 Years
Line impedance testing to improve relay accuracy - as necessary	Not Performed	As requested
Enhanced Outside Plant Maintenance Plans		
Distribution pole inspections	Undefined	10 Years
Vegetation management - distribution circuit trim program	6-7 Years	4 Years

Source: DR 921.

- Within the substation, several asset classes have had their frequencies adjusted to enhance the maintenance program and improve overall system performance. Examples include; switchgear maintenance moved from 10 years to 6 years, substation breakers were advanced from 8 to 6 years and transformers were advanced from 8 to 6 years. These changes are consistent with industry practice.
- Wood distribution and transmission poles are inspected for overall health on a 10-year cycle by an outside contractor.
- Automatic circuit re-closer inspection and repair – These switches are inspected annually for any observed deficiencies and repairs made on an as needed basis.
- Automatic throw over switch inspection and repair - These switches are inspected annually for any observed deficiencies and repairs made on an as needed basis.
- Underground transmission manhole inspection and repair – These manholes are inspected by the OH/UG Lines organization with half the systems manholes inspected each year.

- Network protector inspection and repair – These protectors are inspected visually every year and a more rigorous maintenance is performed every three years on these devices.
- Distribution infra-red inspection and repair – These inspections are performed by an outside contractor every two years looking for hot spots that could lead to failure.
- Transmission infra-red inspection and repair – These inspections are performed by an outside contractor every year looking for hot spots that could lead to failure.
- Capacitor bank inspection and repair – These inspections are performed annually by Distribution Operations with minor repairs made as needed.
- Vegetation management tree trim and tree removal – This program covers the entire distribution system on a 4-year cycle. Transmission system trim is performed on a 4-year cycle (on average), with 250 of the 1000 circuit miles trimmed each year.[42]

10. Preventive maintenance trend analyses are limited and anecdotal as they are largely associated with observed performance issues.

- Substation Maintenance acquires and reviews data for inside plant assets such as transformers and breakers. This data is analyzed to determine signs of health deficiencies. PSEG LI plans for the Asset Strategy group to review the list of assets and determine if additional data sampling is necessary to better understand the trends being observed.[43]

- System Reliability reviews OMS outage data for outage cause, such as equipment failures, tree impact, or weather. Outage frequencies are trended and initiate follow up field inspections for analysis. Inspections typically reveal tree/vegetation contact or substandard equipment as the root cause to the outage trends being observed.

- Data for station transformers and circuit breakers is entered into the new CMMS system for data analytics processing, which is intended to provide visibility into leading indicators of potential failure. Asset Management is continuing to accumulate and input data to provide “greater intelligence” to the algorithms within CMMS.[44] It appears that the need for trend analyses is identified but presently only a work in progress.

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[42] DR 123 and 921

[43] DR 389

[44] DR 912

11. PSEG LI uses rudimentary schedules for preventive maintenance which simply note the units of maintenance activities to be performed over specified monthly, seasonal and annual time periods.

- Maintenance activity units do not have quantified man-hour time standards (discussed in greater detail in **Chapter X – Work Management**). Resource requirements and activity levels are merely correlated to staffing and budget levels.[45]

- T&D system preventive maintenance is scheduled, performed, and recorded using SAP. Each organization described in Conclusion 10 is budgeted to perform its traditional preventive maintenance activities.[46] For inside plant preventive maintenance work scopes, maintenance plans are loaded into the SAP work management module with assigned frequencies. Each year, the work coordination team extracts the next year's maintenance plans to schedule the work force. When maintenance orders are completed in the field, the work coordination team completes the work order in SAP. Work completed can be tracked and monitored by running periodic SAP reports.

- For outside plant preventive maintenance, the maintenance plans are generally tied to the associated distribution circuit. Annual scheduling of outside plant preventive maintenance programs is driven by the various owners of the different maintenance plans. Scheduling of this work is manual, since the plans are not built directly into SAP.

- The tools used to manage work scheduling are simple spreadsheets and databases.

- Some PSEG LI maintenance activities are targeted for spring and early summer each year in anticipation of summer peak system loads. This effort is referred to as a "summer readiness program." Most of these summer readiness programs use a monthly tracking report to monitor status and progress.[47]

- Contractors are used in maintenance areas typical of industry norms, scheduled throughout the year and used on the following maintenance programs:

    - Vegetation management
    - Infrared thermography measurements (repairs are performed in-house)
    - Pole inspections (replacements are completed using in-house resources).

- The preventive maintenance schedules used by each PSEG LI organizational unit include the following.[48]

    - Overhead/Underground Lines – Within each division, work coordination teams schedule the daily/weekly work to construction within the broader capital and

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[45] DR 386, 388, 390 and 613

[46] DR 386 and 390

[47] DR 914

[48] DR 388

expense work schedule to establish start/end dates. Preventive maintenance work is program-based work with target completion dates for the program, set for pre-summer or for end of the annual period. Work coordination teams schedule this work along with other work types, balancing priorities as emergent work arises.

- Substation Maintenance – All of this organization's preventive maintenance work is contained within SAP. Each year the next set of maintenance work is reported out of SAP for scheduling. Work coordination/planning teams create work packages for the maintenance crews from this annual plan within SAP.
- System Protection Operations – Similar to substation maintenance, all of this organization's preventive maintenance work is contained within SAP. Each year the next set of maintenance work is reported out of SAP for scheduling. Work coordination/planning teams create work packages for the maintenance crews from an annual plan within SAP.
- Distribution Operations – Preventive maintenance work is scheduled using spreadsheets to track various programs on an annual basis.
- Distribution Automation – Preventive maintenance work is scheduled using spreadsheets to track various programs on an annual basis as well as the capacitor database application that is an Oracle database accessible via the intranet and developed by the Critical National Infrastructure (CNI) group.
- Meter Operations – The organization utilizes spreadsheets as well as SAP to schedule the various annual maintenance programs.
- Vegetation Management – Contractor-performed maintenance is scheduled using data within SharePoint. Excel spreadsheets are used to track circuits scheduled in a given year's program and note progress to completion.

12. Preventive maintenance goals and budgets are based largely on historical trends.

- To prepare its rate plan submission for 2016-2018, PSEG LI used historical maintenance activities/budgets as a baseline to determine the required preventive maintenance and associated budgets. PSEG LI increased preventive maintenance activities and its forecast annual preventive maintenance spend in the budget it presented for BOT approval.[49]

- As discussed in Conclusion 13, PSEG LI adjusted legacy maintenance frequencies based on the PSE&G New Jersey T&D maintenance programs.[50] During the LIPA transition, PSEG LI performed an assessment of PSE&G's preventive maintenance practices to determine if any adjustments should be made to improve equipment performance. This assessment resulted in a modification of frequencies in certain areas as well as additional maintenance plans.

  - Within the inside plant category, information was gathered from the New Jersey Asset Management organization which participated in a utility panel to compare

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[49] DR 548

[50] DR 549

  maintenance practices and was the basis for any adjustments made to the PSEG LI maintenance plans.[51]
  - Areas such as the vegetation management program were modified based on industry studies. As a result, the legacy tree trimming program was refined to establish a 4-year cycle for addressing distribution system trim maintenance.
  - The pole inspection program was modified to a 10-year cycle which aligns with leading industry practice. PSEG LI believes the 10-year cycle is a common industry standard.

- PSEG LI uses historical trends and budget levels to establish staffing requirements for operational groups that perform preventive maintenance (T&D maintenance and construction, field service, warehouse, workshops, fleet management/maintenance).[52]

  - The 2015 Rate Plan highlighting PSEG LI Staffing was proposed and ultimately recommended in the 2015 Three Year Rate Plan.
  - The on-going staffing requirements are managed by the managers within the operational groups. When additional staffing is required, the managers will make a request to their Directors and ultimately to the PSEG LI President & COO. An Excel file is used by the T&D Business Partner to track staffing.

- Preventive maintenance activities are budgeted, approved, and managed based on the DPS approved rate case for 2016-2018.[53]

  - For each budget cycle, responsible organizations contribute to the cost planning process to ensure that there are adequate resources and funding to support the defined plans within SAP.
  - As the year progresses, monthly actual costs are extracted from SAP and provided to the executing groups for review. Forecasts are provided and variations from the original cost plan are identified within the variance analysis process.
  - Additionally, the recently created Asset Strategy organization has the oversight responsibility for these maintenance programs and works closely with the executing organization to assure plans are being executed within the required time frame and allocated budget. Decisions regarding the need to modify maintenance plans due to budget concerns are the responsibility of Asset Strategy.[54]

13. PSEG LI managers have timely information regarding the T&D system.

- Types and sources of information available to T&D system managers for monitoring the T&D system and making decisions related to preventive maintenance are readily available and include the following.[55]

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[51] DR 550
[52] DR 87
[53] DR 391
[54] DR 913
[55] DR 387

- Information systems data readily available via personal computers and mobile devices:

    - CMMS – algorithm based system tracking data associated with station transformers and breakers and focusing on assets that require further diagnostics. Plans are in motion to add underground transmission data to this system in 2017.
    - Transmission and Substation data collection – monitoring electric system parameters i.e. watts, vars, amps, etc.
    - Hydran monitoring – real time monitoring of station transformers for critical combustible gasses.
    - Distribution circuit reliability performance data – outage data accumulated from OMS used and analyzed to prescribe remedial action, i.e. circuits chosen for circuit improvement program.

- Information available via survey data, reports and equipment maintenance records:

    - Dissolved gas analysis sampling – dissolved gas analysis obtained on request for sample data.
    - Distribution, Transmission and Substation infra-red monitoring for hot spots – thermography of critical components on the system for potential failure points.
    - Cable insulation testing – testing of insulation integrity to determine health of cable systems.
    - Wall thickness pipe monitoring – ultrasonic measurements of metal pipe associated with pipe type cable system.
    - General mechanical function testing of network protectors, cap banks, switches – operation of devices to ensure proper movement and mechanical functionality.
    - Pole strength analysis – sound and bore of poles to determine remaining strength. Any significant decay will be remediated with chemical treatments.
    - Right of Way (ROW) survey for vegetation encroachment – annual surveys of transmission rights of way identifying areas for tree trim or whole tree removals.
    - Hazard tree inspection program – inspection of transmission and distribution lines for danger trees that are suspect and could jeopardize the infrastructure.
    - Distribution circuit load analysis/balancing – annual review of system loads per phase conductor and transfer of loads to balance across three phases. Cathodic system testing for pipe type cables – various testing activities validating integrity of the system mitigating any corrosion of the metal pipe associated with underground transmission system.

14. **PSEG LI's vegetation management practices have become more aggressive, reflect adopted industry best practices, and are appropriate for LIPA's service territory.**

- Differences between utilities and even within service territories result in different vegetation management practices geographically, often due to:
  - Types of foliage
  - Foliage growth rates
  - System designs
  - Customer aesthetics.
- PSEG LI has a vegetation management organization that includes nine vegetation management specialists and one forester. The group is responsible for:
  - Managing assigned tree trim and maintenance contracts
  - Assigning work to contractor crews
  - Inspecting the work for conformity to Company standards
  - Ensuring accurate reporting of work and costs
  - Participating in municipal and customer outreach to explain programs
  - Interfacing with individual customers for private property access permissions and to satisfy customer requests
  - Directing tree-related restoration efforts during storms and other system emergencies.[56]
- PSEG LI identifies outages that are specifically related to vegetation. This allows PSEG LI to assess the effectiveness its vegetation management program. **ExhibitVIII-8** provides the annual SAIFI (including major storms) for the transmission and distribution system related to vegetation outages. SAIFI related to vegetation has steadily increased since 2014.

Exhibit VIII-8
Vegetation Outage SAIFI (including major storms)

Year	Transmission	Distribution
2014	0	0.18
2015	0	0.22
2016	.005	0.31

Source: DR 113.

- PSEG LI has redesigned its vegetation management program to include recognized industry best standards with an anticipated reduction in SAIFI. The vegetation management program is specific to both transmission and distribution.

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[56] DR 120

  - A best practices study for vegetation management was conducted in 2013.[57] The study assessed PSEG LI and other utilities considered have service territories similar to LIPA against 22 criteria.
  - PSEG LI modified its vegetation management program based on the results of the study. In particular:

    - Development of both a vegetation management plan and annual schedule
    - Development of estimates of number and removal standards of "hazard" trees
    - Development of clearance specifications, trimming cycle, and regrowth rates
    - Improvements to contractor performance auditing,[58]

- PSEG LI has approximately 1,000 circuit miles of overhead transmission. The transmission vegetation management program includes the following enhancements:

  - Historically, 200 miles per year of vegetation management was funded, resulting in a 5-year trimming cycle. PSEG LI has adopted a four-year cycle or 250 miles per year.
  - The sideline clearance was increased to 25 feet for 138 kV lines. All other transmission is trimmed to 18 feet clearance.
  - An entire tree removal program was developed for hazard trees in bulk corridors.

- The distribution vegetation management program includes the following enhancements:

  - Increased the circuit miles trimmed from 1,600 to 2,220 annually resulting in a trim cycle of four years from almost six years.
  - Expanded the line clearance from a 6 feet radius to a box that is 8 feet of clearance on each side by 10 feet of clearance below by 12 feet of clearance above the conductor.[59]
  - Coordinated with asset management modeling to determine priority trimming.
  - Developed an entire tree removal program for hazard trees within the line clearance standard.

- In addition, to traditional transmission and distribution trimming and removal programs, PSEG LI also has four special programs:

  - Storm Hardening/Hazard Tree Removal
  - Customer Support
  - ROW/Substation Maintenance
  - Targeted Vine Mitigation.[60]

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[57] DR 738 Environmental Consultants, Inc. July 31, 2013

[58] DR 738

[59] DR 401

[60] DR 120

15. PSEG LI has recently met annual vegetation management goals albeit at increased budget levels.

- PSEG LI did not complete the number of planned distribution system miles to be trimmed in 2014 or 2015. On November 8, 2016, PSEG LI formally committed to completing the planned 2014-2017 trim cycle in 2017. This required PSEG LI to increase mileage by 20 percent in both 2016 and 2017, and resulted in spending in excess of budget dollars in both 2016 and 2017.[61] **Exhibit VIII-9** shows budget, actual spend and miles trimmed.

- PSEG LI completed its T&D trimming cycle over four years within eight percent of budget. PSEG LI underestimated the costs associated with its special programs (Storm Hardening/Hazard Tree Removal, Customer Support, ROW/Substation Maintenance, and Targeted Vine Mitigation.) The entire cycle was within twelve percent of budget.

- The benefits of completing the trim cycle have become apparent in late 2017. NorthStar analyzed the number of customers interrupted due to vegetation for the first nine months of 2016 and 2017 and found a 39 percent reduction in customers interrupted. For the first nine months in 2016, 301,458 customers were interrupted as compared to 183,306 in 2017.[62]

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[61] DR 121

[62] DRs 113 and 916.

Exhibit VIII-9
Vegetation Management Performance

	2014	2015	2016	2017	Total
Distribution					
Budget	$23,700,000	$15,760,673	$17,750,000	$17,750,000	$74,960,673
Actual/Forecast	$19,701,913	$16,185,545	$23,341,643	$28,008,259[1]	$82,237,360
Planned Miles	2,220	2,220	2,220	2,220	8,880
Actual/Forecast Miles	1,840	1,735	2,666	2,639[2]	8,880
Transmission					
Budget	$2,870,000	$3,000,000	$3,000,000	$3,300,000	12,170,000
Actual/Forecast	$2,700,308	$2,871,804	$3,120,000	$3,667,303[1]	$12,359,415
Planned Miles	250	250	250	250	1,000
Actual/Forecast Miles	255	250	242	253[2]	1,000
Transmission and Distribution					
Budget	$26,570,000	$18,760,673	$20,750,000	$21,050,000	$87,130,673
Actual/Forecast	$22,402,221	$19,057,349	$26,461,643	$31,675,562	$94,596,775
Planned Miles	2,470	2,470	2,470	2,470	9,880
Actual/Forecast Miles	2,095	1,985	2,908	2,892	9,880
Planned T&D Cost/Mile	$10,757	$7,595	$8,401	$8,522	$8,819
Actual T&D Cost/Mile	$10,693	$9,601	$9,100	$10,953[3]	$9,575
Special Programs					
Budget	$8,620,000	$6,472,293	$6,900,000	$7,000,000	$28,992,293
Actual/Forecast	$7,943,626	$5,769,796	$9,967,327	$12,167,000	$35,847,749

Note 1: PSEG LI Forecast
Note 2: NorthStar Calculation – miles required to finish trim cycle
Note 3: Forecast based on 1 and 2.
Source: DRs 120,121, 122, and 916; NorthStar Analysis.

16. PSEG LI effectively contracts for its vegetation management program.

- NorthStar's conclusion is based on meeting vegetation goals, spending within budget levels, and execution by competitively bid contracts.

- PSEG LI competitively procures its vegetation management services. Bids are solicited as lump sum for a defined scope of work or unit price (i.e., per mile or per tree).

- PSEG LI has multiple vendors across the service territory. Multiple vendors are key to maintaining competitive pricing. During the audit period, PSEG LI maintained vegetation trimming and tree removal contracts with seven different vendors over multiple years.[63] This number of vendors permits local and regional coverage for the service territory, cost comparisons among providers and flexibility.

- Vegetation management vendors are evaluated annually by PSEG LI Vegetation Management specialists based on four criteria:

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[63] DR 739

  - Quality
  - Customer Service
  - Leadership
  - Communication.[64]

- PSEG LI dedicates personnel to vegetation contract management, invoice review, and inspections. Contractors submit invoices for work performed on a monthly basis or project basis (depending on contract structure). Each contractor's work is inspected monthly and evaluated for quality and completeness.[65]

- PSEG LI recognizes opportunities for improvement in its specifications for vegetation management:

  - Overhanging limb incidents averaged between 6.24 percent and 8.6 percent of total reportable customer interruptions over the past four years. This represents an opportunity to further reduce outages through contractor management and/or trimming specification.
  - "Entire trees falling over" incidents averaged between 6.42 percent and 9.82 percent of total reportable customer interruptions over the past four years. This represents an opportunity to further reduce outages through the Hazard Tree Inspection program.[66] The program identifies and removes hazard trees identified by a certified arborist that pose a threat to Distribution and/or Transmission facilities. Hazard trees may show signs of imminent structural failure due to disease (such as Oak Wilt) or infestation (such as Pine Bark Beetles).

Repair/Replace and Reactive/Corrective Maintenance

17. PSEG LI has a reasonable approach to repair/replace decision-making but it lacks cost/benefit analyses.

- In November 2015, PSEG LI issued its first formal repair/replace procedure, a twelve-page policy titled "Repair Versus Replace Decisions for LIPA T&D Assets," intended to provide guidance for repair/replace investment decisions relating to T&D assets.[67] The policy covers all common T&D operational functions and inside/outside plant asset categories.

  - NorthStar's 2013 LIPA Management and Operations Audit noted that there was no written policy or procedure documentation.
  - Historically, the approach to repair versus replace decisions has been driven by urgency, repair difficulty, and the availability of replacement parts or equipment. In short, the decisions were based on field observations and judgment.

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[64] DR 402
[65] DRs 739 and 836.
[66] DR 917
[67] DR 65 Attachment 1

- Although PSEG LI now has a guidance policy regarding repair versus replace decisions, the guidance is subjective and the decision making remains judgmental, i.e., equipment repairs versus replacement are determined by the maintenance personnel directly involved. The policy does not provide economic tradeoff analyses or justification because PSEG LI does not have quantified labor costs or standards for maintenance activities. This is discussed in **Chapter X – Work Management**.

- The guidance policy lists asset types for which repairs may be costlier than a direct replacement of that asset, and/or the desire to return the system to normal quickly precludes a repair. These assets/equipment types include those listed in **Exhibit VIII-10**.

Exhibit VIII-10
Assets that are Generally Replaced, Not Repaired

Asset	Rational for Replacement
Outside Plant Assets	
Pole top transformers	Failure mode is typically catastrophic and immediate replacement is necessary.
Pad mounted transformers	
URD transformers	
Voltage regulators	
Switching devices	While no formal maintenance program exists for these devices, at times a minor repair can be made. Otherwise these devices are typically run to failure.
Inside Plant Assets	
Transmission cable terminations	No formal maintenance program exists for this asset.
Low voltage equipment	
Manually operated disconnect switches	No defined maintenance plans exist for this asset class and switches are typically run to failure.

Source: DR 65 Attachment 1

- The logic behind a "run to failure" philosophy (essentially, replace upon failure rather than repair) is straightforward. While an asset is functioning as designed, maintenance while operationally deployed is minimal due to difficulty or marginal impact on the asset's life expectancy. Assets that fall into this category typically:

  - Can be remedied quickly without a dramatic impact to customer satisfaction, safety, or system reliability
  - Are not considered "critical" to the operation of the system
  - Are difficult to predict the timing of the impending failure.

- PSEG LI classifies outside plant assets such as pole top transformers and below grade transformers as "run to failure" as it is impractical to cost effectively assess their overall health condition, unless there are visible oil leaks.[68]

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[68] DR 393

Outage Management – System Improvements and Performance

18. PSEG LI has installed an improved OMS system that provides better customer service and increased efficiency.

- PSEG LI replaced the legacy CARES OMS with a CGI OMS in August 2014.
    - Prior to 2014, PSEG LI used the CARES OMS. The CARES OMS was a legacy system with little integration with new technology and no adaptation to customer needs.
    - The CGI OMS is a "next generation" system that can be integrated with other utility systems such as the SCADA, Geographic Information Systems (GIS), Customer Accounting System (CAS) etc.

- The new CGI OMS system offers the following improvements:
    - Introduction of SCADA data allows for earlier detections of equipment operation and potential cause of outage.
    - The mapping of customer calls to the GIS system and SCADA equipment operation identifies the number of affected customers, permitting prioritization of work and best allocation of restoration resources.
    - Due to increased field information, PSEG LI can better provide estimated time to restore information to customers and local officials.
    - The CGI OMS interacts directly with the PSEG LI website, permitting customers to report an outage online or via text (along with traditional telephone). The system permits customer call-back and texting concerning outages.

19. The new CGI OMS system captures data reliably and in a timely fashion. However, PSEG LI experienced unintended consequences regarding how data was reported.

- NorthStar attended OMS demonstrations and tours of the customer call center. During these field observations, NorthStar observed that the OMS system operated seamlessly and instantaneously.

- The OMS had an initial problem with double counting affected customers. This situation occurred when:
    - An outage had overlapping causes. When the initial outage was cleared, all customers would have been seen in the system as restored. After an overlapping outage or second cause of outage was cleared a portion of the customers was shown again as restored.
    - Outages have not been re-analyzed on circuits requiring additional analysis.

  - Large buildings with multiple-services are not always on the same alternating current phase. When one phase is cleared, the customers in the building are cleared and when the next phase is cleared the customers are recounted.[69]

- The OMS also resulted in increased counts in the number of outages and the number of customers interrupted.

  - During the restoration process, a circuit is often energized and de-energized multiple times.
  - Each time, the SCADA system is registering an outage and recording it in the OMS. The instances are included in OMS. The CARES system was not integrated the SCADA system in this manner and the reliability data would not have registered the multiple operations.
  - PSEG LI currently has a reliability engineer review system outages associated with multiple operations to determine accurate customer counts.

- PSEG LI has changed the OMS data to accurately reflect customer counts. The changes have been independently audited and validated.[70]

20. PSEG LI developed a comprehensive emergency restoration plan (ERP) dated December 15, 2014 and has updated the plan annually.

- An Incident Command Center has been formally established.

- Protocols for training have been documented.

- The current ERP is dated December 15, 2016, and addresses the following:

  - Personnel Responsibilities
  - Mitigation Activities
  - Storm Anticipation
  - Emergency Classifications
  - Establishment of Priorities
  - Outage Management
  - Estimated Time of Restoration
  - Safety, Health and Environment
  - Legal Protocols
  - Liaison Protocols
  - Communication Protocols
  - Operations Protocols
  - Planning Protocols
  - Logistics Protocols
  - Finance/Administration Protocols
  - DPS Protocols.[71]

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[69] DR 561, IR 73

[70] DR 561

- PSEG LI updates the ERP on an annual basis and incorporates lessons learned.

    - PSEG LI recognizes the importance of integrating lessons learned into its ERP. The PSC-required Part 105 Scorecard submittal after a major event, requires the identification and integration of lessons learned.
    - During the period of this audit, there were no restoration events of the magnitude required for a Part 105 submittal.[72]
    - PSEG LI prepares Storm Summaries for each major storm event. For larger scale events, PSEG LI prepares "Storm Summary and Improvement Plan" reports. Section 3 of the report provides a matrix identifying focus areas that did not perform as anticipated, opportunities for improvement, action items, responsibility and a schedule for completion.[73]
    - PSEG LI's original ERP is dated December 15, 2014. It was submitted to the DPS and subsequently revised based on DPS comments on April 17, 2015.
    - Revision 1 of the ERP is dated December 15, 2015. It was submitted to the DPS and based on DPS comments revised on April 22, 2016.
    - Revision 2 of the ERP is the current plan and is dated December 16, 2016.

21. As of August 2017, PSEG LI's emergency response training was incomplete.

- The purpose of training is to improve PSEG LI's readiness during an emergency. PSEG LI has properly identified emergency response training requirements, but not all employees have been trained as specified in the ERP.

- The ERP states that *all* PSEG LI employees are assigned specific storm restoration assignments and that they are required to fulfill them when emergency conditions dictate.

- The ERP recognizes that the normal functions of many employees are not part of daily system operations and that training is crucial to change the roles of these employees.

    - PSEG LI requires that all employees receive training based on their expected roles and skill sets.
    - The ERP includes a detailed matrix of training classes and target audience. Each training class is supported by syllabus of the materials and specific targeted employee classes.[74]
    - PSEG LI offers FEMA-sponsored online training. Currently it is voluntary and PSEG LI is working on a methodology to formally distribute and track this training.[75]

- PSEG LI also conducts emergency response drills and exercises:[76]

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[71] DRs 118 and 398

[72] DR 727

[73] DR 399

[74] DRs 398, 724, and 725

[75] DR 726

  - The ERP identifies two types of exercises: discussion-based and operations-based.
  - PSEG LI has established a schedule to conduct ten specific exercises annually. **Exhibit VIII-11** provides the details of completed exercises. As shown in the exhibit, PSEG LI has not conducted a Cross-River Resource Sharing exercise since 2014. However, several actual storm events tested the companies' sharing procedures.[77]

Exhibit VIII-11
Completed Drills and Exercises

Drill/Exercise	Discussion Based	Operations Based	Number of Drills			
			2014	2015	2016	2017
Alternate Control Center Drill		X	1	1	1	1
Logistics Exercise	X	X		1	1	1
Crew Processing Exercise	X	X		1	1	1
Communications Exercise	X					1
Planning Section Exercise	X				1	2 [Note 1]
Hurricane Exercise	X		1	1	1	1
Cross-River Resource Sharing	X		1			
Division Communications Exercise		X				1
Divisional Survey		X	4		4	4
Dispatch Area Workshops		X		8	8	8

Source: DRs 398, 728 and LIPA/PSEG LI Fact Verification.
Note: A third exercise is planned Q4 2017.

- PSEG LI has approximately 2,300 employees. For emergency response training, employees are divided into those with job responsibilities that do not change significantly during a storm response and those with job responsibilities that change during a storm response.

  - PSEG LI states that the approximately 1,200 employees that do not change responsibility during a storm response are trained on an ongoing basis as part of their day-to-day activities. PSEG LI does not believe these employees require separate emergency response training. Typical positions in this category include linemen, system operators, and electrical and mechanical technicians. NorthStar finds that PSEG LI is inconsistent in this matter, as the ERP is not explicit that certain employees are excluded from emergency response training.
  - Of the remaining 1,100 employees, approximately 250 to 300 do not receive ERP training and they would receive instruction before an event. PSEG LI believes these employees would have responsibilities very similar in nature to non-storm responsibilities. Positions in this category include major account representatives.[78]
  - The remaining 800 to 850 employees require specialized ERP training.

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[76] DR 728
[77] DR 728 and LIPA/PSEG LI Fact Verification
[78] DRs 118 and IR 222

- Training is typically conducted annually, in the late spring. PSEG LI does not normally provide make-up sessions for employees and defers training until the following year. PSEG LI stated that they work with employees individually to schedule their attendance at alternate training classes or exercises if there is a scheduling conflict. In some instances, make-up sessions are offered.[79]

- PSEG LI provided training records for 788 employees. PSEG LI believes this to be representative of the group of employees that have emergency response roles that are different from their blue-sky roles. **Exhibit VIII-12** provides that training statistics for the 788 employees. Forty-nine employees scheduled for training have not attended training as of August 2017.[80]

Exhibit VIII-12
Training Statistics

Employee Training Status	Number of Employees
Attended Training	519
Did Not Attend Training	49
Scheduled for Future Training	138
Disability	8
New Employees – Not yet Scheduled	74
Total	**788**

Source: DR 726.

- The ERP does not address training requirements in sufficient detail.
  - The ERP does not identify the type of training to be received by position (on the job, workshop, online, formal classroom, training drills etc.)
  - While the ERP identifies formal classroom training classes, there is no recommended frequency to the training. Twenty-seven of 788 employees have not received training since 2014.[81]
  - PSEG LI indicated that there are recommended training frequencies by position but they are not included in the ERP.[82]
  - The ERP does not identify which positions are exempt from ERP training.[83]

D. RECOMMENDATIONS

The most important recommendation for improving PSEG LI's T&D operations, preventive maintenance and continued improvement require workload resource quantification and can be found in **Chapter X – Work Management**.

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[79] IR 222 and LIPA/PSEG LI Fact Verification
[80] DRs 2 and 726
[81] DRs 398 and 725
[82] DR 118
[83] DR 725

1. Continue implementing the vegetation management program to meet annual targets. Complete the mainline hardening program.

2. Complete the Emergency Response Training for all employees as required.

3. Improve Emergency Response Training description in the ERP to identify type of training and frequency by position.

4. Complete development of the CMMS.

5. Continue monitoring SAIFI both from a system and cause basis. Continue targeting and prioritizing programs that address reliability.

IX. PROGRAM AND PROJECT PLANNING AND MANAGEMENT

Capital projects are investments in LIPA's electric system to preserve assets, ensure or improve system reliability and safety, protect the environment, or expand operating efficiency or capacity. Project scope, budget, 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 are fundamental to demonstrating feasibility, analysis of alternatives, and demonstration of project benefits. Early program and project planning includes the decisions and processes that shape a project and determine its success.

The full implication of many project management decisions cannot be known until project completion. NorthStar's 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. Fortunately, there is a robust body of knowledge defining "generally recognized good practices" in portfolio, program, and project management. Among them are the following:

- Comparison of Construction Management and Program Management Fees, Construction Management Association of America, 2014
- Best Practices Procurement and Lessons-Learned Manual, Federal Transit Administration, October 2016
- Business Process Change: A Guide for Business Managers & BPM (Business Process Management) & Six Sigma Professionals, 2nd Edition, July 2007
- Construction Management Standards of Practice -- 2015 Edition; Construction Management Association of America (CMAA)
- Government Design-Bid-Build Work Breakdown Structure (WBS), Project Management Institute, 2006
- Guide to the Project Management Body of Knowledge (PMBOK® Guide), 6th Edition, Project Management Institute, September 2017
- Organizational Project Management Maturity Model – 3rd Edition, Project Management Institute (PMI), 2013
- Publicly Available Specification (PAS) 55: 2008 Specification for the Optimized Management of Physical Assets Parts 1 and 2, British Standards Institution
- Project Management Institute Government Extension to the PMBOK Guide, 3rd Edition, September 2006
- Standard for Program Management, 4th Edition, Project Management Institute, October 2017

A. BACKGROUND

The Amended and Restated Operations Service Agreement (A&R OSA) dated December 31, 2013, assigns PSEG LI broad responsibilities in the capital improvement, operations, and maintenance of the transmission and distribution systems. Responsibilities include the development and preparation of:

- Recommended capital plans and the monitoring of the approved annual capital budget.
- Risk assessments and analyses in support of capital projects prioritization and planning.
- Long and short range system plans, including integrated electric resource plans.
- Proposed annual operating and maintenance work plan.
- 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.
  - Project management services to ensure the technical performance and reliability of the T&D system.
  - Meeting 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.

- Capital improvements and repair or modification activities required due to Public Works Improvements.

The A&R OSA further requires PSEG LI to monitor, analyze, and report on:

- The supervision and management of capital projects including engineering and related design and construction management services.
- Monthly budgets for both capital and operating expenses for the services provided by PSEG LI.
- Monthly and year-to-date budget to actual variances, and explanations of such variances.
- Financial projections based on variance analyses.[1]

PSEG LI provides project management and project controls in its Business Services Organization. The Vice President of Business Services reports directly the President and Chief Operating Officer of PSEG LI. **Exhibit IX-1** shows the organizational units within Business Services that provide program and project management activities.

The A&R OSA stipulates PSEG LI will provide LIPA on an annual basis:

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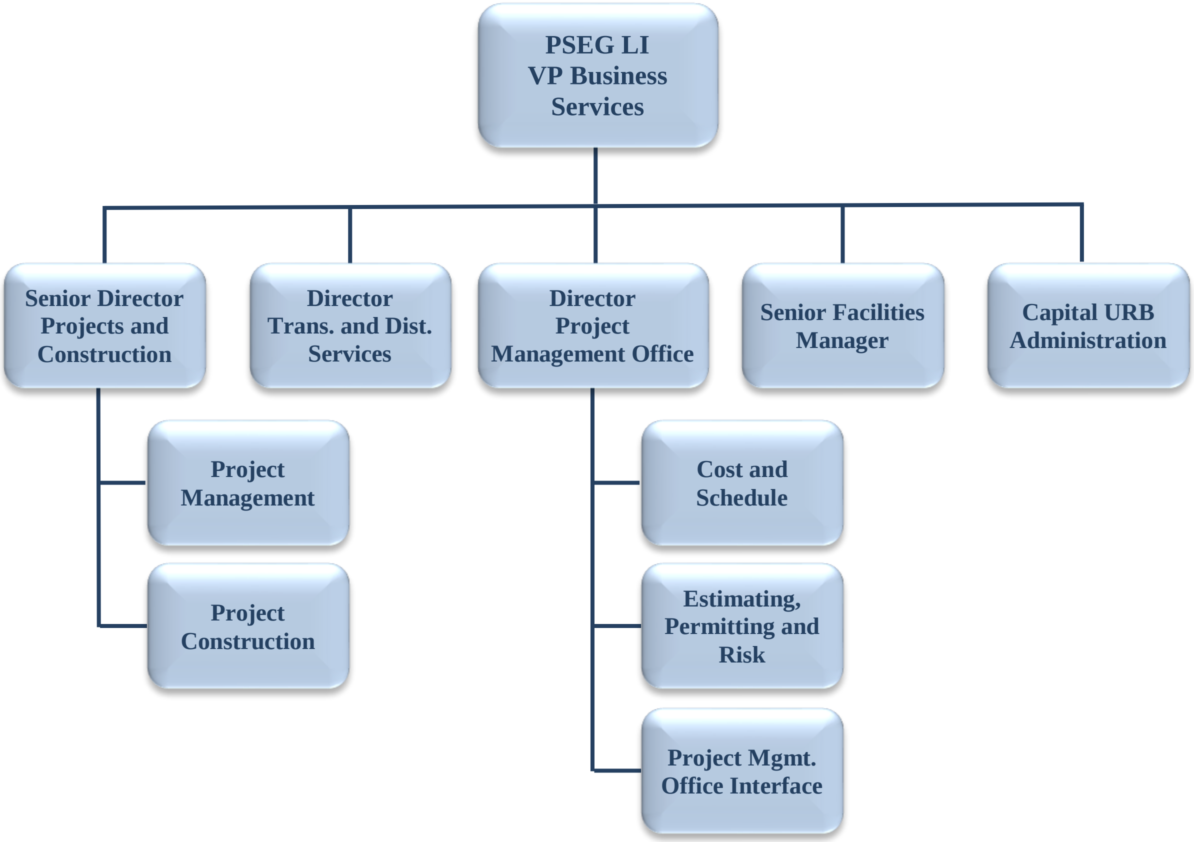
[1] DR 4 – A&R OSA Section 4.2.A.1

- An annual audit of capital improvement made in the prior contract year. The audit scope shall include the accuracy of plant records, maps, and asset maintenance databases.
- Physical inventory of all capital assets from time to time.

Exhibit IX-1
Business Services Organization



Source: DR 830 and LIPA/PSEG LI Fact Verification

PSEG LI manages the LIPA capital program through its Utility Review Board (URB). The URB is responsible for:

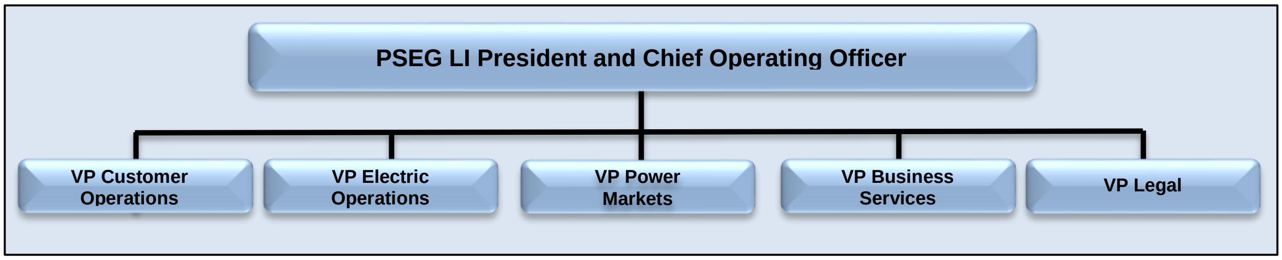
- Providing oversight to PSEG LI's capital budget for the business planning horizon.
- Reviewing PSEG LI's investment projects to ensure affordability, priority, and possible alternatives analysis.
- Reviewing project alternatives to ensure appropriateness of pursued project.
- Reviewing PSEG LI's capital spending estimates for the upcoming year and tracking actual spending against estimates.

The URB is composed of seven members including the President and Chief Operating Officer of PSEG LI, his direct reports (shown in **Exhibit IX-2**), and the PSEG LI Director of

Finance, who reports to the PSE&G Finance Vice President.[2] The URB approves funding for:

- All transmission and distribution (T&D) capital improvement projects including facilities, blankets and specific projects. Blankets are a number of similar projects that are less than $250,000 in aggregate. Specific projects are greater than $250,000.
- All information technology (IT) projects greater than $500,000.[3]

Exhibit IX-2
PSEG LI Organization



Source: DR 830

The Transmission and Distribution Planning Coordinating Council (TDPCC) is responsible for providing updates on current and future projects. The TDPCC is scheduled to meet every two weeks and is comprised of LIPA and PSEG LI Directors, Managers and Engineers.[4]

PSEG LI's Project Management Playbook (PMP) was developed to guide project managers and the project team through the activities required when developing a capital project. The PMP defines a formal project life-cycle for the delivery of capital projects. The project life-cycle has five phases, where completed deliverables and activities permit movement to the next phase. Phases and key elements within each phase include:

- Project Initiation
  - Project Scope Document
  - Develop work breakdown structure
  - Level 1 Schedule
  - Develop office or study level estimate
  - Identify resources
  - Assemble Project Team

- Preliminary Engineering/Design
  - Project execution plan
  - Project scope plan
  - Project estimating

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[2] DR 2
[3] DR 558
[4] DR 62

  - Quality Assurance/Quality Control (QA/QC) Plan
  - Safety Plan
  - Risk Management Plan

- Detail Engineering/Design
  - Detailed Plans and Specifications
  - Review schedule
  - Bid awards
  - Definitive Level Estimate

- Construction
  - Delivery of materials
  - Licensing and Permitting
  - Identify field supervisors, managers etc.
  - Evaluate progress
  - Manage Change Orders

- Completion
  - Start-up and commissioning
  - Project review and lessons learned
  - Close-out activities[5]

PSEG LI has developed a number of key policies and procedures that support the PMP. Each procedure is organized similarly with defined purpose, application, responsibilities, process and required documents.

- Project Authorization
- Project Scope Management
- Project Scheduling Management
- Project Cost Management
- Project Execution Plan
- Construction Management and Contract Administration
- Invoice Management[6]

The audit compared current written procedures (stated practice), and actual practices, to preferred practices such as those referenced above.

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[5] DR 475

[6] DR 73, 76, 81, 475, 476, and 963

B. EVALUATIVE CRITERIA

The audit of Program and Project Planning and Management followed the list of baseline evaluative criteria provided by the DPS and an overall assessment of the effectiveness of the Authority's and Service Provider's operations management.[7]

- Are programs and projects prioritized and approved over various time horizons in a cost-effective manner?
- Are program and project planning, design, estimating, engineering, costing, scheduling and execution functions well documented and performed to recognized standards for good practice?
- Are materials and equipment, transportation and other logistical support planned and managed effectively for programs and projects?
- Is there optimum use of in-house workforce versus contractor labor?
- Are contractor and engineering bidding practices appropriate?
- Are construction contractor projects planned and managed effectively?
- Do LIPA and PSEG LI have effective quality assurance and quality control at the program and project level?
- Do LIPA and PSEG LI have effective contractor management and project/program management, including accountability, goals, objectives, and performance measurement?
- Do LIPA and PSEG LI utilize a well-defined structure to estimate, track and monitor project performance and is it used consistently?
- Is monitoring and controlling against project baselines for scope, budget, and schedule performed?
- Are project scope changes effectively controlled and communicated among participants?
- Do LIPA and PSEG LI have an effective methodology for prioritizing and approving capital projects?
- Is the construction/capital priority setting process balanced, consistent and appropriately executed from the top down?
- Do capital plans and budgets convert to specific programs and projects in an effective manner?
- Does capital project estimating produce accurate results that are sufficiently detailed to yield accurate cost estimates?
- Are relationships among planned/budgeted expenditures and actual expenditures appropriate?
- Do LIPA and PSEG LI track and minimize variances in order to improve the cost control, efficiency/productivity and work quality?
- Do LIPA and PSEG LI routinely identify typical variances between original budgeted and actual capital expenditures and work units?
- Do LIPA and PSEG LI have an effective methodology for tracking costs, work units and work quality for specific programs and projects?

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[7] DPS RFP and Bidder's Package for Matter 16-01248, August 5, 2016

C. FINDINGS AND CONCLUSIONS

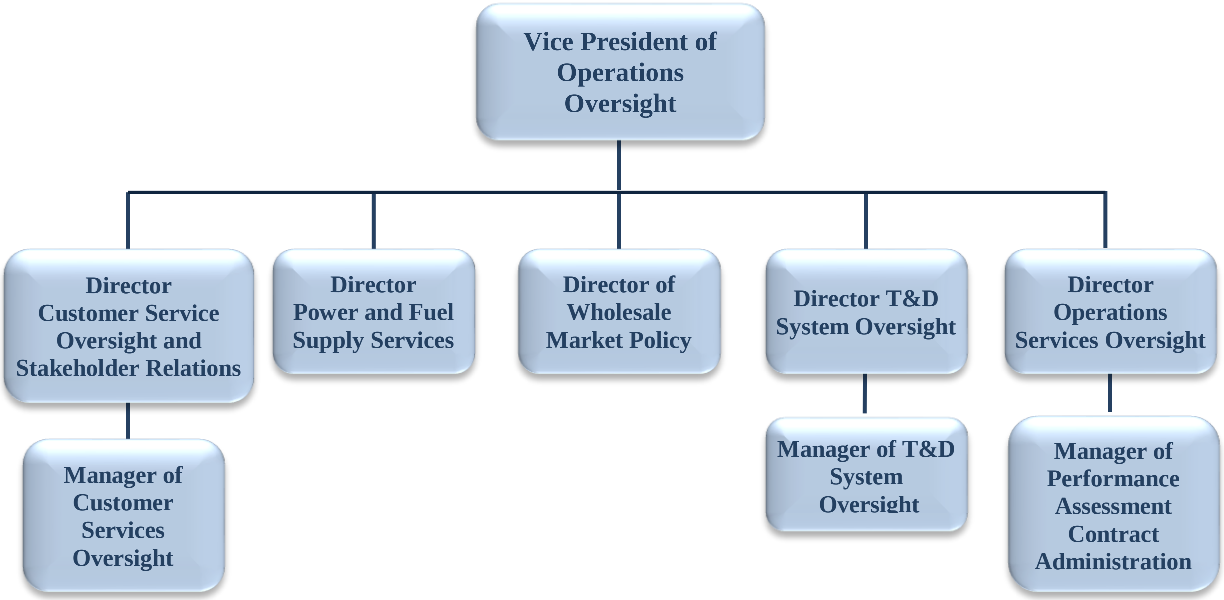
1. LIPA's oversight of PSEG LI's capital program and project implementation is performed at a high level.

- LIPA's T&D program and project level management oversight roles and responsibilities are established in its contract with the Service Provider under Section 4.3 of the A&R OSA:[8]

> As the owner, lessor or controlling entity of the T&D System, LIPA retains the ultimate authority and control over the assets comprising the T&D System. In connection therewith, LIPA has continuing oversight responsibilities and obligations with respect to the operation and maintenance of the T&D System and the Service Provider's provision of the Operations Services hereunder.

- LIPA's T&D system and capital program oversight is assigned to two professionals: the Director of T&D Oversight and the Manager of T&D Oversight. **Exhibit IX-3** provides LIPA's Operations Oversight Department. Three individuals provide various T&D program and project system oversight responsibilities including the Vice President Operations Oversight.[9]

Exhibit IX-3
LIPA Operations Oversight Department



Source: DR 1 – Revised Attachment 1.

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[8] DR 4 Attachment OSA
[9] DR 1 and 293

- LIPA developed two primary documents that define its roles, responsibilities, controls and procedures for the oversight of capital programs and projects under the A&R OSA:[10]

  - The "LIPA Control and Responsibilities Document, Contract Oversight" document (dated April 2014) covering Management of T&D Assets is very high level, as described below:[11]

    - The management activities identified in the document are primarily monitoring performance metrics, attending meetings and reviewing PSEG LI documents.
    - Performance measures directly related to capital project delivery such as the following are not addressed:
      - Scheduling (e.g., number of projects and activities that are behind schedule)
      - Estimating (e.g., projects and WBS elements that exceed estimates)
      - Approvals, budgets and change control (e.g., what changes have been approved to program/project costs, scope and schedule)
      - Progress/Updates (e.g., number of projects that have cost and/or schedule changes)
      - Project life-cycle (e.g., measured progress against annual and multi-year plan)

    - Program and project oversight is focused on budget not on progress or individual program or project reviews.[12] Monitoring project expenditures against budgets is not meaningful project cost management as there is no determination of *earned value* for amounts spent.

  - The "LIPA Contract Oversight Department Responsibilities and Procedures" document (dated March 2015) minimally addresses oversight of capital project delivery.[13] The document lacks definitions of what is considered a major capital project and lacks procedures for monitoring and tracking. The document largely covers administrative functions, A&R OSA metrics, and notes various areas to be monitored. T&D system oversight is a two-page list of monitoring and review areas.

- LIPA's most recent operations oversight work product is the "Annual Report of Operations Oversight Department" covering calendar year (CY) 2016 dated October 2017. With respect to program and project management, the operations report focuses on budget spending by portfolio and programs, and does not address capital

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[10] DR 293
[11] DR 293 Attachment 2
[12] DR 293
[13] DR 293 Attachment 1

project delivery. Actual program and project accomplishments such as the amount of planned work actually completed for amounts expended are not addressed.[14]

- NorthStar also requested examples of the information provided to LIPA by PSEG LI as required by the A&R OSA Section 4.13 Part A:

  > The Service Provider shall include in each such Capital Budget a description of each capital project constituting Capital Improvements in sufficient detail to enable LIPA to make a fully informed analysis and assessment thereof including (i) the project location, (ii) the planned initiation date and expected duration, (iii) an estimate of the amount of the costs including the dollar amount per year if the project requires more than a year to complete, (iv) an explanation of the relationship to other planned or subsequently required Capital Improvements, (v) the anticipated useful life of each Capital Improvement and (vi) the economic and engineering justifications for such project.

  LIPA stated that the analysis called for in A&R OSA Section 4.13 A, is a process – a steady stream of meetings and communications. The continuous dialogue with PSEG LI as described by LIPA does not produce an analytical work product and NorthStar concluded that only a high-level of monitoring is performed.[15]

- LIPA and PSEG LI have conducted a number of compliance audits related to Federal Emergency Management Agency (FEMA) guidelines and project management. LIPA has not conducted any internal audits of non-FEMA capital projects.[16]

2. **PSEG LI's project management and project controls organizational structure appropriately separates project management functions from project execution.**

- PSEG LI re-organized its transmission and distribution functions in August 2017. **Exhibit IX-1** provides the current organization of project management functions. Organizational separation between project management and project execution improves managerial independence among the two functional areas.

- Project management was previously located in transmission and distribution operations. The function has been consolidated into two groups: Projects and Construction and Project Management Office (PMO).

  - Project Management is conducted through the Projects and Construction Organization.
  - Traditional project controls such as cost and schedule analysis is conducted through the PMO.
  - The PMO is also responsible for project estimating.

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[14] DR 294, Attachment 2

[15] DR 4 and 833

[16] DR 34 and 35

- The consolidation of project managers into one organization permits a more efficient allocation of work to resources.

- The separation of project controls from project management provides an objective and independent analysis of progress.

- Electric Operations is responsible for operations, maintenance and construction work in each PSEG LI division.

3. PSEG LI's capital project review and selection methodology identifies the most critical projects for system reliability.

- 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 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.[17]

- PSEG LI stated that all capital projects are identified for consideration by the URB using information contained in the Project Justification Document (PJD) and a Capital Project Investment Request.[18] The information requirements include:

  - Full description of system need or problem
  - Cost, benefit, and basis for solution recommendation
  - Alternative analysis
  - Work scope
  - Associated projects[19]

- The goal of the prioritization system is to select projects that provide the most value to LIPA's system. PSEG LI uses an optimization model that objectively compares discretionary capital projects resulting in funding of the cost-effective projects.

- Each T&D capital project is assigned a risk score to provide guidance in the selection and prioritization of projects and programs in the capital budget. Project risk scores are reviewed in July and August for start dates planned for the following calendar year.

- PSEG LI divides projects into two categories: discretionary and mandatory. Mandatory projects are projects that are required due to contractual terms and legal

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[17] DR 42, 59, 60 and 61

[18] DR 66 and 81 Attachment 1

[19] DR 238

mandates. All projects receive a risk score; however mandatory projects are included in the budget regardless of score.[20]

- Projects are ranked 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.

- Prioritization is used as a guideline for developing the initial list of selected projects. The selected projects are reviewed by the Investment Delivery Assurance organization to ensure there is adequate work distributed during the planning period to support the utilization of in-house and anticipated contracted labor forces. LIPA stated that Operations Oversight reviews the capital budget of selected projects including PJD, UMS Spend Optimization Suite (SOS) and related data prior to the final budget presentation to the Board of Trustees.[21] Once PSEG LI and LIPA have reached agreement on the budget, it is presented to the Board for approval.

- Prior to 2017, PSEG LI used a combined evaluation of project impact and likelihood, to determine a risk score for each capital project in its capital project portfolio.

    - Project impact was comprised of four equal and separate categories, which included regulatory requirements, customer service requirements, financial performance, and technical performance. For each category, a project was assigned a score ranging from 1 to 10. Scoring was completed by responding to a series of questions about the project, which are listed by category and found in individual scoring tables.
    - Likelihood referred to the risks associated with an equipment failure or malfunction event. This category considered 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 was calculated by multiplying the project's scores in the exposure, probability, and detection categories.
    - The overall risk score of the project was calculated by multiplying the highest individual impact score for all categories (regulatory requirements, customer service requirements, technical performance, and financial performance) and the likelihood of that particular impact occurring. In general, only a single likelihood needed to be considered, unless the impact scores are close and associated with different likelihood scores. If a project scored high in multiple categories, consideration was given for multiple benefits in the scoring as illustrated in **Exhibit IX-4**.
    - Risk scores determined which projects would be included in the yearly budget submittal, and were therefore are a major factor in project prioritization.

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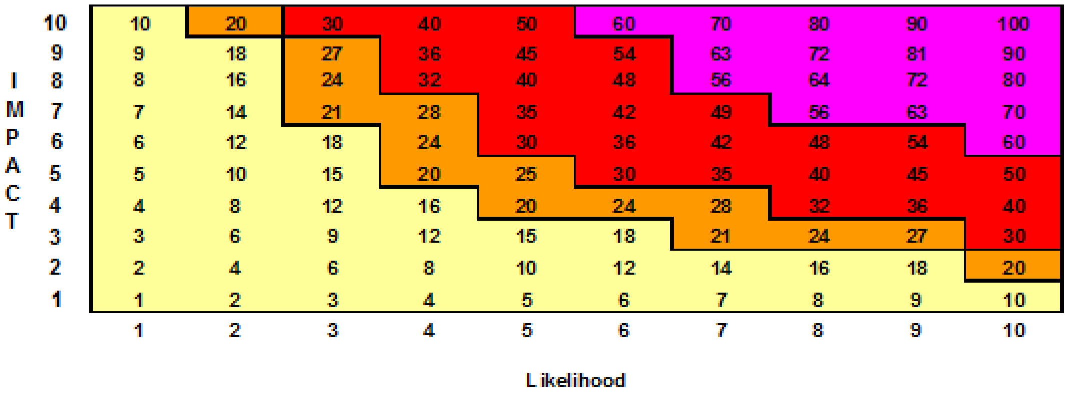
[20] DR 502

[21] DR 833

Exhibit IX-4
Risk Scoring Impact-Likelihood Matrix

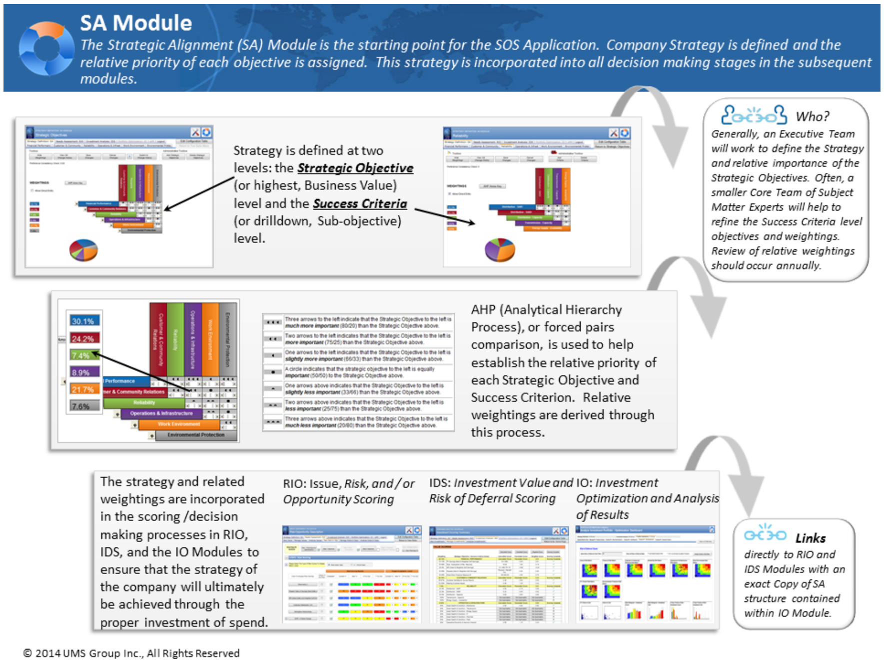


10	10	20	30	40	50	60	70	80	90	100
9	9	18	27	36	45	54	63	72	81	90
8	8	16	24	32	40	48	56	64	72	80
7	7	14	21	28	35	42	49	56	63	70
6	6	12	18	24	30	36	42	48	54	60
5	5	10	15	20	25	30	35	40	45	50
4	4	8	12	16	20	24	28	32	36	40
3	3	6	9	12	15	18	21	24	27	30
2	2	4	6	8	10	12	14	16	18	20
1	1	2	3	4	5	6	7	8	9	10
	1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

Source: DR 786.

- <u>During 2017</u>, PSEG LI adopted the SOS to prioritize capital projects and used this in developing the 2018 capital budget. The SOS system is similar in nature to the previous methodology in that its goal is to rank projects that provide the most value to LIPA. The system provides a three-year prioritized project portfolio.
  - The SOS uses algorithms to optimize the portfolio when considering budget, need date, and project cost estimate. The results of SOS however are impacted by the weaknesses in the estimation process (see Conclusion 12).
  - The SOS analysis begins with identification and weighting of LIPA's strategic objectives. **Exhibit IX-5** provides the methodology used by SOS to evaluate strategic objectives.

Exhibit IX-5
Strategic Objective Module of SOS



SA Module

The Strategic Alignment (SA) Module is the starting point for the SOS Application. Company Strategy is defined and the relative priority of each objective is assigned. This strategy is incorporated into all decision making stages in the subsequent modules.

Strategy is defined at two levels: the ***Strategic Objective*** (or highest, Business Value) level and the ***Success Criteria*** (or drilldown, Sub-objective) level.

Who?

Generally, an Executive Team will work to define the Strategy and relative importance of the Strategic Objectives. Often, a smaller Core Team of Subject Matter Experts will help to refine the Success Criteria level objectives and weightings. Review of relative weightings should occur annually.

◄ ◄ ◄	Three arrows to the left indicate that the Strategic Objective to the left is ***much more important*** (80/20) than the Strategic Objective above.
◄ ◄	Two arrows to the left indicates that the Strategic Objective to the left is ***more important*** (75/25) than the Strategic Objective above.
◄	One arrows to the left indicates that the Strategic Objective to the left is ***slightly more important*** (66/33) than the Strategic Objective above.
●	A circle indicates that the strategic objective to the left is equally ***important*** (50/50) to the Strategic Objective above.
▲	One arrows above indicates that the Strategic Objective to the left is ***slightly less important*** (33/66) than the Strategic Objective above.
▲ ▲	Two arrows above indicates that the Strategic Objective to the left is ***less important*** (25/75) than the Strategic Objective above.
▲ ▲ ▲	Three arrows above indicates that the Strategic Objective to the left is ***much less important*** (20/80) than the Strategic Objective above.

AHP (Analytical Hierarchy Process), or forced pairs comparison, is used to help establish the relative priority of each Strategic Objective and Success Criterion. Relative weightings are derived through this process.

The strategy and related weightings are incorporated in the scoring /decision making processes in RIO, IDS, and the IO Modules to ensure that the strategy of the company will ultimately be achieved through the proper investment of spend.

RIO: Issue, *Risk, and / or Opportunity Scoring*

IDS: *Investment Value and Risk of Deferral Scoring*

IO: *Investment Optimization and Analysis of Results*

Links

directly to RIO and IDS Modules with an exact Copy of SA structure contained within IO Module.

Source: DR 66

- PSEG LI identified four strategic objectives with the following weightings:

  - Economics (weighted at 15 percent) – Revenue Recovery.
  - People (weighted at 10 percent) – Human and Physical Work Environment.
  - Green (weighted at 10 percent) – Environmental and Business Operations, Renewable Energy Generated, Energy Efficiency Savings, Fleet.
  - Safe and Reliable (weighted at 65 percent) – Customer service and Operations, Asset Health, Reliability Indices, JS Power, PSC LIPA Inquiries, Asset Operations and Proficiency.[22]

- Projects are evaluated based on their relative value to the strategic objectives and the risk of deferral. This is accomplished through a series of test questions against each potential project.
- SOS permits multiple scenario analyses. **Exhibit IX-6** provides the methodology in SOS of how scenarios are evaluated.

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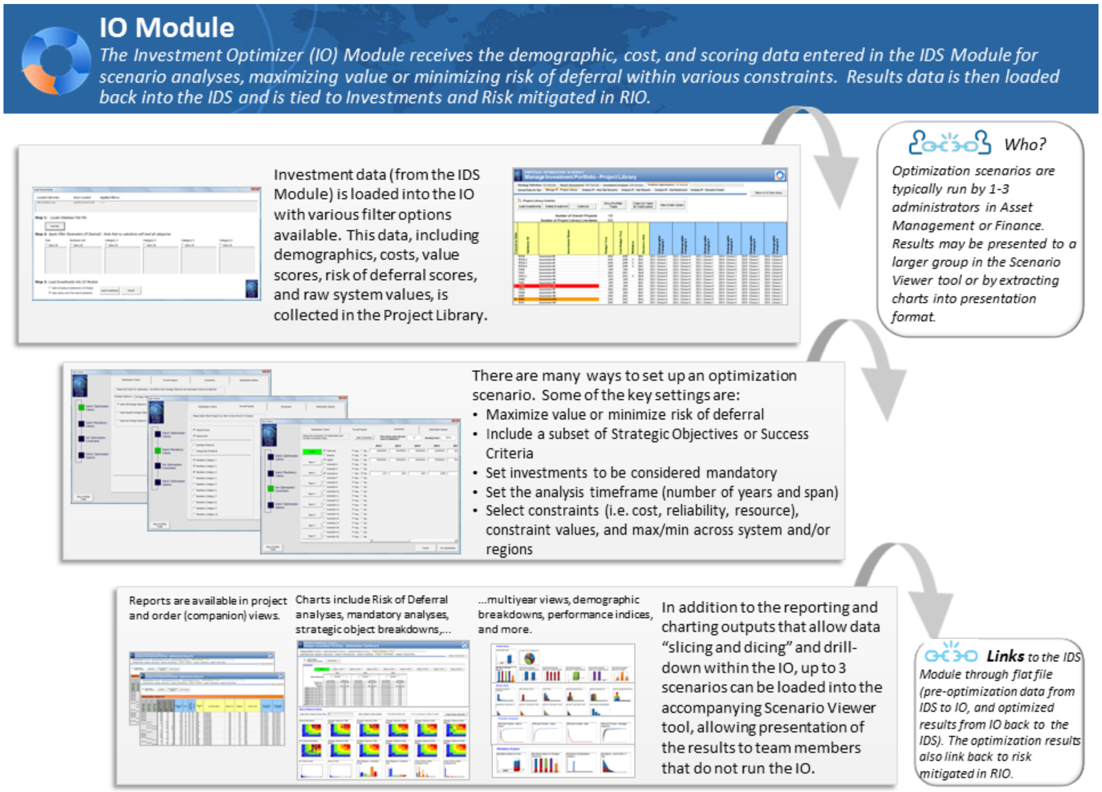
[22] DR 66

Exhibit IX-6
Scenario Analysis and Optimization in SOS



IO Module

The Investment Optimizer (IO) Module receives the demographic, cost, and scoring data entered in the IDS Module for scenario analyses, maximizing value or minimizing risk of deferral within various constraints. Results data is then loaded back into the IDS and is tied to Investments and Risk mitigated in RIO.

Investment data (from the IDS Module) is loaded into the IO with various filter options available. This data, including demographics, costs, value scores, risk of deferral scores, and raw system values, is collected in the Project Library.

Who? *Optimization scenarios are typically run by 1-3 administrators in Asset Management or Finance. Results may be presented to a larger group in the Scenario Viewer tool or by extracting charts into presentation format.*

There are many ways to set up an optimization scenario. Some of the key settings are:

- Maximize value or minimize risk of deferral
- Include a subset of Strategic Objectives or Success Criteria
- Set investments to be considered mandatory
- Set the analysis timeframe (number of years and span)
- Select constraints (i.e. cost, reliability, resource), constraint values, and max/min across system and/or regions

Reports are available in project and order (companion) views.

Charts include Risk of Deferral analyses, mandatory analyses, strategic object breakdowns,...

...multiyear views, demographic breakdowns, performance indices, and more.

In addition to the reporting and charting outputs that allow data "slicing and dicing" and drill-down within the IO, up to 3 scenarios can be loaded into the accompanying Scenario Viewer tool, allowing presentation of the results to team members that do not run the IO.

***Links** to the IDS Module through flat file (pre-optimization data from IDS to IO, and optimized results from IO back to the IDS). The optimization results also link back to risk mitigated in RIO.*

Source: DR 66.

PSEG LI develops four categories of project list scenarios based on:

- Value Optimization
- Risk Minimization
- Optimization with Mandatory Projects
- Optimization without Mandatory Projects

- The SOS determines priority scores for each project for each scenario. Scenario results are compared side-by-side. Projects (investments) that are selected in all four scenarios then ranked the highest.[23]

- The SOS was used for the first time in the preparation of the 2018 budget. The results of the model indicated that 99 percent of available capital funds are already dedicated for the next three years due to multi-year projects.[24]

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[23] DR 66, 362, and 957

[24] DR 966; IR 220

4. **PSEG LI has improved procedures related to program and project planning, and management.**

- PSEG LI's PMP (Procedure TD-PM-001-0003) provides the fundamentals for capital project delivery. The PMP covers:

    - High-level roles and responsibilities
    - Project Phases (Project Initiation, Preliminary Engineering, Detailed Engineering, Construction, Completion).
    - Major Activities associated with each project phase
    - Project Manager's responsibilities in each phase
    - Level of Estimates

- Seven procedures support the functions of program project planning, design, estimating, engineering, costing, schedule and execution. All seven procedures are similar in structure and include roles and responsibilities, documentation, and methodology.[25]

    - Project Authorization (Procedure TD-PM-001-0001)

        - The primary purpose of this procedure is to establish the authorized spend for a project and to obtain approved funding.
        - The Project Authorization (Procedure TD-PM-001-0001) covers three primary areas:
            - Initial funding authorization
            - Additional funding authorization
            - Project Close-out

        - The procedure identifies key documents to be submitted to the URB for funding consideration including:
            - Capital Project Justification Investment Request
            - Project Justification Document
            - Capital Accounting Determination
            - Project presentation slide for URB
            - Estimates at each phase of project[26]

        - The Vice President of T&D Operations is responsible for approving funding requests and submission to PSEG LI Board of Directors (BOD).

    - Project Scope Management (Procedure TD-PM-001-0004)

        - The primary purpose of this procedure is to obtain agreement among all project participants regarding their respective roles, work products and communicating changes in scope to all participants.

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[25] DR 81 Attachments and 475

[26] DR 73

- The project scope is considered "locked down" when input has been received from all key project participants. A Project Scope document is developed, and is then approved by PSEG LI management.
- The project scope document is a detailed five-page description of the project, and includes:
  - Project Information, including participants, dates, cost, etc.
  - Project Overviews
  - Goals and Objectives
  - Service Dates
  - Deliverables
  - Exclusions from Scope
  - Assumptions
  - Risks
  - Constraints/ Long Lead Time Items
  - Operating Contingencies/ Outages
  - Environmental Land Use and Remediation Checklist
  - Related Projects
  - Project Team members and contact information
  - Approvals[27]

- The project scope document identifies the protocols for managing project scope changes.
  - Project scope changes are initiated by the completion of a Project Scope Change Request by the requesting organization.
  - Approval is required by the Project Manager, Manager of Project Management, the Manager of Project Control and the Director of Projects and Construction.
  - The project manager is then responsible for coordinating the request and evaluating for budget, cost, schedule, cash flow and funding.
  - If the change is approved, the project manager is responsible for communicating with the directors of Projects and Construction and Asset Management and the project team.
  - If the scope change results in significant changes to require funding beyond approved budget and requires the transfer of contingency funds, the Project Manager is required to submit a Project Change Request Form.[28]

- The URB is responsible for approving funding for scope changes. The project manager is responsible for the preparation of slide for the URB meeting.
- URB packages used to conduct meetings include Project Change Request Forms.[29]

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[27] DR 73

[28] DR 73 and 84

[29] DR 558

- Project Scheduling Management (Procedure TD-PM-002-0002)

  - This procedure identifies the sequence of activities that will result in delivery of capital projects on-time. It includes the following elements:
    - A work breakdown structure (WBS) to be used across T&D project delivery.
    - Identifies Primavera P6 as the scheduling platform and SAP as the work management tool.
    - The development of a baseline schedule (initial plan) that is to be archived with the project file. Progress will be evaluated against the baseline schedule.
    - Full accounting of project scope.

  - The procedure identifies the creation of the following documents:
    - Gantt Charts
    - Activity Reports
    - Critical Path Gantt Charts
    - Variance Reports
    - Look ahead Reports
    - Expediting Reports[30]

- Project Cost Management (Procedure TD-PM-002-0004)

  - This procedure covers the development of cost estimates by activity that supports then-approved funding and scope of work.
  - Key components in the procedure include the following:
    - Preliminary Estimates and project inclusion in Five-Year Budget Plan
    - Accounting Set-up
    - URB approval
    - Estimate levels
    - Establishment of target budget
    - Changes in target budget
    - Defines four levels of estimate: Office, Study, Conceptual and Definitive.

- Project Execution Plan (Procedure TD-PM-002-0001)

  - This procedure identifies the key project progress elements.
  - Applicable to projects greater than $8 Million.[31]
  - The procedure includes a checklist identifying the necessary documents. Required documents may include:
    - Project Charter – Statement of work, deliverable, justification
    - Scope Management Plan
    - Cost Management Plan

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[30] DR 73

[31] DR 990

        - Schedule Management Plan
        - Project Authorization Plan
        - Invoice Management Plan
        - Environmental Management Plan
        - Staffing Plan
        - Status Reporting Plan
        - Communications Plan
        - Licensing and Permitting Plan
        - Construction Plan
        - Close-out Plan

- Construction Management and Contract Administration (Procedure TD-CM-001-0001)

    - This procedure provides the methodology to obtain formal approval to outsource goods and services.
    - It covers:
        - The approval process to outsource services.
        - The phases and steps of a contract lifecycle.
        - Tasks and responsibilities for each phase.
        - Techniques in the writing of specifications.[32]

- Invoice Management (Procedure TD-CM-001-0002)

    - This procedure provides guidance to determine if invoices are correct and that LIPA received the products and services as specified.[33]
    - The procedure provides:
        - Invoice approval process and references delegation of authority controls.[34]
        - General techniques for evaluating invoices. This includes comparing the billing structure (hours, units, etc.) of the contract with the structure of the invoice and verification that the materials and services billed are correct.

5. **PSEG LI's procedures developed to date address many components of capital project delivery, but as yet have not evolved to fully support project management and control.**

- The seven PSEG LI project management procedures described above, lack a sufficiently clear purpose.[35] A typical procedure purpose statement is:

> "The purpose of this procedure is to develop formal Capital Project Management policies and procedures that support the Project Management Playbook, as per change requirements established by the North Star audit,

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[32] DR 73, 76

[33] DR 73, 76, 81, 475, 476, and 963

[34] DR 646

[35] DR 81

> and will support successful execution of major capital projects for Transmission & Distribution (T&D). In addition, this procedure will set forth the procedure established by the T&D [organization] for obtaining and managing project funding authorization, managing and controlling project funding change requests, and performing technical and financial project closeouts pursuant to Utility Review Board (URB) requirements."[36]

The purpose does not immediately identify the necessity of the procedure, or the risk of not following the procedure in terms of what is to be prevented or controlled. Also, the purpose of a procedure should not be merely to satisfy the finding of an audit or regulatory oversight. The purpose of the procedure is to manage and control costs in a professional manner to maximize value.

- The Cost Management Procedure does not address cost management; it is an estimating procedure.[37] It needs formalized procedures and methodology on what to evaluate, how to evaluate, and how to manage the results related to costs incurred for capital projects.
- The Schedule Management Procedure similarly does not address schedule management, rather it addresses schedule development.[38] It needs procedures and methodology on what to update, how to update, and how to manage the results of a schedule update.
- The Invoice Management Procedure references the PSEG LI delegation of authority (management levels of approval authority based on dollar limits) but does not specify the thresholds.
- The Project Execution Plan is a checklist of document requirements.[39] It does not provide guidance on how to prepare and approve the numerous documents required in the procedure or how they are to be used in actual practice. Fundamentally, the Project Execution Plan does not address project evaluation per se, whether the Project Execution Plan is even being followed, or what actions to take if the Plan is not followed.

6. PSEG LI has not fully adopted and implemented the PMP and the seven procedures to deliver capital projects.

- PSEG LI's PMP requires four estimate levels:
    - Office – Desk-top estimates based on project scope document and major equipment lists.

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[36] DR 81, Attachment 1
[37] DR 81, Attachment 7
[38] DR 81, Attachment 3
[39] DR 81, Attachment 10

  - Study – Study estimates are prepared by the project manager. It is based on additional information including one-line drawing, schedule, and risk analysis.
  - Conceptual – This estimate is prepared during preliminary engineering and includes the contract strategy, environmental and permitting factors, and preliminary engineering and technical specifications.
  - Definitive – This estimate is based on final design packages and bids from equipment and contractors.[40]

- NorthStar conducted a review of the progression of 62 project estimates for projects in progress and found estimates were not completed as required.

  - 36 projects required conceptual-level estimates and 16 were not provided.
  - 43 projects required study-level estimates where only 10 were prepared.
  - 62 projects required office-level estimates. Three generic estimates that were not project specific were used for 31 projects.[41]

- Project Execution Plans are checklists and do not contain fully developed plans.[42]

- PSEG LI does not archive schedules as required. NorthStar was provided the most recent schedule for a sample of projects. There was no chronological archive from the baseline schedule and the comparison of baseline to progress at each project phase as required in the Schedule Control Procedure.[43]

7. PSEG LI does not use an industry accepted work breakdown structure (WBS).

- PSEG LI does not utilize a WBS as defined by the Project Management Institute, a nationally-recognized and venerable trade organization.[44]

- By definition a WBS is deliverable-oriented and hierarchal. Its purpose is to create a structured approach for project execution that objectively demonstrates *earned value* for the completion of project elements and their respective expenditures. For example, a new substation WBS organizes project elements into logistical bundles such as foundation, equipment installation, wiring completion, grounding completion, and conduit completion. These components would further breakdown into the activities necessary to complete the individual components. Importantly, a WBS identifies a deliverable the result of the effort, not the effort itself.[45]

- PSEG LI identified a WBS as including Civil Engineering, Electrical Engineering, Civil Construction, Legal, Environmental, Corporate Communications, Landscaping/restoration, Licensing and Permitting, etc.[46] This is not a WBS, but

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[40] DR 475
[41] DR 647
[42] DR 990
[43] DR 81and 758
[44] IR 17
[45] 2008 Project Management Institute. *A Guide to the Project Management Body of Knowledge*, 4th Edition.
[46] DR 419

rather activities and groups of cost categories. These costs do not necessarily represent earned value for expenditures or tie to a delivered work product. Therefore, PSEG LI cannot demonstrate the earned value of the funds expended during the construction of capital projects and not until the entire project has been completed.

- PSEG LI does not use a deliverable-oriented WBS but rather a six-phase project schedule: Planning, Design and Engineering, Licensing, Procurement, Construction and Closeout. Projects are not estimated by phase and none of the phases can show earned value or a delivered asset.[47]

8. PSEG LI recognizes weaknesses in its estimating process and is working to improve program and project estimating.

- Current estimating techniques are not adequate, lacking in detail, and do not contain supporting data.
  - PSEG LI states that current estimating is based on a series of in-house spreadsheets. The spreadsheets are based on recent costs and maintained in two data warehouses on its SharePoint site.[48] PSEG LI could not provide information on validating the accuracy of the estimating data, the applicability of the data, and how often the data is updated.
  - Based on risk and contingency factors, PSEG LI assigns confidence levels to each estimating level (60, 65, 70 and 90 percent). Confidence levels by definition refer to the percentage of all possible samples that can be expected to include the true population parameter.[49] NorthStar's analysis could not determine how confidence levels are used arithmetically to adjust project estimates.
  - PSEG LI did not provide any support of sampling and statistical analysis or a meaningful definition of how confidence levels are used or are applicable to an estimate process.[50]
  - Estimates are increased with a risk and contingency factor, ranging from 40 percent for an office level estimate to ten percent for a definitive estimate. These factors artificially inflate project budgets as the factors appear unsubstantiated.[51]
  - Project budgets are then established using this inflated value: poor estimates multiplied by 1.40. Risk and contingency is applied to the entire project estimate and is not a separate cost category.
  - The SAP system does not retain multiple versions of project estimates.

- NorthStar conducted a review of original approved budget amounts to final budget amounts and completed costs for projects completed from 2014 through 2016. These projects showed significant deviations between original and final budget and from

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[47] DR 758

[48] DR 458

[49] http://stattrek.com/statistics/dictionary.aspx?definition=confidence_level

[50] DR 459 and 460

[51] DR 760

final budget to completion cost. The variances were both on an individual project and portfolio basis. **Exhibit IX-7** provides the variance analysis.

- **Exhibit IX-7** shows that project budgets are inaccurate and routinely increased beyond the risk and contingency amount (an additional 31 percent aggregate difference between original budget and final budget).
- The final cost of the projects in the sample shows that neither estimate nor the budget is accurate.
- Final project cost is more often below final approved budget. [52]

Exhibit IX-7
Projects Completed 2014-2016: Budgets to Completion Cost Variance
(All dollars are shown in $1,000s)

Project Description	Total Original Budget	Total Revised Budget	Final Cost	Estimate Variance	Completion Variance
Amagansett Terminal Ring Bus	$16,468	$22,280	$21,979	35%	-1%
Arverne Replace 33 kV Switchgear (Sandy)	$4,101	$8,790	$8,258	114%	-6%
Barrett – Replace Switchgears 7 & 8	$8,000	$9,600	$7,626	20%	-21%
Barrett – Valley Stream EGC (138–292)	$7,100	$11,000	$10,529	55%	-4%
Bohemia Exit Feeder (7BH–3K7) and OH C&R	$1,600	$1,520	$1,607	-5%	6%
Buell – Instl3PH M/LConn–9E–985–9R–777	$745	$677	$665	-9%	-2%
Deshon Development Melville - C&R	$1,210	$1,000	$657	-17%	-34%
EGC – Meadowbrook 69–465	$2,100	$10,000	$6,844	376%	-32%
Elwood 13kV UG cable bypass C&R	$440	$400	$346	-9%	-13%
Elwood Install 80 MVAR Reactor	$3,912	$5,600	$5,515	43%	-2%
Far Rockaway – Replace Switchgear 7 & 8	$5,000	$8,000	$6,840	60%	-15%
Floral Park (3B)	$7,000	$11,420	$11,736	63%	3%
Great Neck – Port Washington Reconductoring	$14,400	$18,400	$16,270	28%	-12%
Green Acres Mall Expansion Assoc C&R	$2,145	$2,145	$1,381	0%	-36%
Holtsville Sub DRSS	$21,000	$21,000	$6,377	0%	-70%
Levittown – Plainedge Reconductor 69–571	$4,000	$6,900	$7,068	73%	2%
LIRR Bellaire Rectifier	$701	$768	$568	9%	-26%
LIRR Colonial Street Bridge Relocation	$1,950	$1,450	$1,046	-26%	-28%
LIRR Ellison Ave Bridge	$508	$314	$(773)	-38%	-346%
LIRR Hicksville Pole Relocation	$1,328	$1,966	$1,313	48%	-33%
LIRR Island Pk Wreck Rd Brdg Line Reloc	$97	$97	$83	0%	-14%
LIRR Oceanside Rectifier	$533	$533	$111	0%	-79%
LIRR Oil City Sub Station	$549	$549	$292	0%	-47%
PAM Solar Reimb – Robert Moses State Park	$1,100	$1,311	$978	19%	-25%
Park Place Add 33MVA 33/13kV bank	$3,976	$8,270	$9,604	108%	16%
Peconic C&R – Reconfigure 8B–7K5, 7K6	$3,960	$3,500	$3,145	-12%	-10%
Pilgrim 13 kV Reconductor C&R	$778	$507	$656	-35%	29%
Riverhead – New Feeder (OH UG Portions)	$4,000	$4,719	$4,767	18%	1%
Riverhead - Repl Swgr-Banks 3&3A / 4&4A	$2,500	$3,400	$3,312	36%	-3%
Rockaway Bch – Inst 13/4kV XFMRS – C&R	$2,300	$2,300	$884	0%	-62%
Rockaway Beach 13kV Switchgear 3 & 4	$4,800	$5,600	$5,601	17%	0%

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[52] DR 79

Project Description	Total Original Budget	Total Revised Budget	Final Cost	Estimate Variance	Completion Variance
South Manor New Sub& Assoc Distribution	$13,517	$13,900	$14,345	3%	3%
Southampton Cable Tap	$3,600	$6,030	$3,236	68%	-46%
Southold-Replace 2 Banks	$3,100	$3,200	$2,398	3%	-25%
Syosset – Add 138/13kV Bank & 1/2 LU Swgr	$5,500	$11,660	$10,370	112%	-11%
Terryville Substation – New Exit Feeders	$5,800	$6,300	$5,641	9%	-10%
Wildwood Sub DRSS	$15,200	$15,556	$15,600	2%	0%
Y-49 Cable Failure - July	$3,748	$4,191	$3,748	12%	-11%
Y-49 Cable Failure - May	$4,643	$4,790	$4,643	3%	-3%
Total	**$183,409**	**$239,642**	**$205,266**	**31%**	**-14%**

Source: DR 79.

- PSEG LI alternatives analyses are made irrelevant due to poor project estimates as well as those of alternative solutions and the inflation of project amounts.

- Prioritization/optimization software such as SOS relies on the cost of a project solution in optimizing value of the portfolio.

- Economic comparison of Reforming the Energy Vision (REV) alternatives versus traditional wires-based project solutions are rendered meaningless without accurate project cost estimates.

- Management oversight and control over capital programs, projects and optimizing the value of capital improvements rely on accurate project estimates. The results of the SOS model as used to develop the 2018 capital budget indicated that 99 percent of available capital funds are already dedicated for the next three years due to multi-year projects.[53]

- The 2013 LIPA Operations and Management Audit Report included three recommendations (10.4.4, 10.4.5 and 10.4.6) related to improving project estimates. As noted in **Chapter II – Background and Prior Audit**, these recommendations have not been completely implemented to date.

- In February 2017, PSEG LI established a formal estimating function within its PMO. PSEG LI currently has two full-time employees, one manager and one supervisor supplemented by two contract employees. PSEG LI is unsure of the final staffing needs, but anticipates two additional full-time employees.[54]

- The estimating department pursued an automated estimating solution for transmission and substation projects. Based on Public Service Electric & Gas' (PSE&G) success, PSEG LI is implementing the "Eos SAGE" estimating system.[55] The system will require integration with the SAP accounting system, the Primavera P6 project

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[53] DR 966; IR 220

[54] DR 619

[55] Eos commercial software applications: https://www.eosgroup.com/overview

management system, and must be populated with recent and relevant data. It is anticipated that Phase I will be completed in third quarter 2018 and will take another two years for full system implementation.[56]

9. **PSEG LI focuses on controlling spending levels and must include value for expenditures.**

- In its Capital Budget Performance Metric, PSEG LI's finance organization determines capital spend by portfolio. It is then compared against the forecast spend for the month and year-to-date.[57] This is a measure of financial performance not a measure of project management performance.

- PSEG LI focuses on consolidated budget to actual expenditures and not as much on the specific performance of individual programs and projects.

  - "Capital Plan Variance" reports concentrate on program monthly actual and planned spend amounts, year-to-date expenditures and yearly variances.[58] Specific programs and projects that are over spent are netted against those under spent.
  - T&D programs are consolidated and reported as "Blanket" and "Specific" categories.
  - Cost reports for T&D specific capital projects are produced monthly and record prior annual actual expenditures along with current year monthly expenditures.[59] Year-end projected expenditures versus budget are highlighted. The focus is on controlled spending.
  - PSEG LI's description of project cost variance management indicated that monthly budget review meetings highlighted expenditures against forecasts along with projected year-end spending. Detailed action items – such as mitigating causes of variances – are not recorded.

- NorthStar requested capital project variances, scope changes, change orders or project re-work that can be or were attributed to the engineering work product. PSEG LI responded that the Estimating Department is currently developing an "Estimate Variance Report" and has begun tracking design and engineering issues that impact the capital portfolio.[60]

- The PSEG LI project controls organization tracks project milestones achieved and project spend against forecast. The portfolios are consolidated and reported as the

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[56] DR 457, 620 and 1007
[57] DR 820
[58] DR 180
[59] DR 254
[60] DR 380

Capital Project Performance Metric.[61] This metric does not measure project controls as there is no individual project accountability.

- Projects can be over or under budget if the aggregate total is on target. If capital spending metrics are jeopardized, project spending is deferred.[62]
- Milestones may be achieved but have no direct relationship to earned value for the dollars spent. PSEG LI stated that project percent complete is "expert judgement" and there is no calculation.[63]
- Comparison of individual project spend is not reconciled with progress reported on the schedule.

- Analysis of "total project" cost based on project estimates is not done. Tracking program and project dollars already spent does not provide meaningful cost management and does not demonstrate earned value for expenditures.

- PSEG LI's Project Authorization (Procedure TD-PM-001-0001) covers procedures for developing capital project management policies and procedures for project funding authorization, managing and controlling project funding change requests, and project closeouts.[64] Utility Review Board (URB) project approval is required to proceed with a capital project based on the Project Justification Documents (PJD) and capital spending plans. A Capital Project Change Request form (PCR) is required for URB approval and documentation of changes in budget, service date, cash flow, and scope. An example of the PCR form is included as Attachment 6 to the procedure, but there is no indication as to when the form or its submittal to the URB is required.

- NorthStar requested URB agendas, minutes, and meeting documentation.[65] PCR forms are used by the URB for initial project funding and increases, PJDs are not.

- PSEG LI's Project Cost Management (Procedure TD-PM-002-004) covers procedures for planning purposes, estimating and URB approval for capital projects expected to exceed $1.0 million.[66] One of the highlighted responsibilities of the URB is to approve estimate level changes – project cost variances. While the procedure addresses numerous approvals and project estimates of various types, when URB approval is required for changes to project estimates/budgets is not covered.

- The URB Charter states that any capital investment exceeding 10 percent of the previously authorized amount requires re-approval by the URB.[67] However, the URB Charter is not mentioned in the procedures noted above.

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[61] DR 600, 873 and 874
[62] DR 180 Attachments 4, 5 and 6, and 254 Attachment 1
[63] DR 447 and 451
[64] DR 81 Attachment 1, Procedure dated 9-25-2015
[65] DR 558
[66] DR 81 Attachment 7, Procedure dated 9-25-2015
[67] DR 558 Attachment 75

- SAP reports are not standardized to support specific management functions such as capital project management. Individual project managers may query the SAP system to obtain project information. PSEG LI does not specify the analyses and frequency to be reviewed.[68]

- Monthly project progress reports are a comparison of forecast to actual expenditures. Variance analysis is rudimentary. Costs variances noted are attributed to high level causes such as forecast error, engineering error, and scope change. The monthly report does not:

  - Report progress against cost and forecast to completion cost.
  - Report budget to actual man-hours.
  - No formal logs of actions items related to project variances.[69]

10. PSEG LI's project schedule management has documented policies and procedures but does not fully adhere to these requirements.

- PSEG LI's Project Scheduling (Procedure TD-PM-002-0002) covers the methods for developing, reviewing, and approving project schedules for T&D capital projects expected to exceed $1.0 million.[70] Highlights include:

  - The procedure identifies numerous management positions and organizational units that participate in the development, review and issuance of project schedules.
  - The project schedules will be inclusive of all project work scope, all phases, and WBS.
  - Baseline schedules are to be created, copied and archived to align with each estimate level change.
  - T&D will use Primavera's P6 scheduling system for all projects.
  - The procedure calls for various schedule levels of detail along with evolution over the project life, updated monthly.

- In practice, PSEG LI uses one schedule level to show all known project activities at the outset, and updates the project schedule with activity completion information.[71]

- Project schedules are not archived. When Primavera P6 schedules are updated prior records are lost.[72] Other than activity completion shown on project schedules PSEG LI could not demonstrate schedule management.

- Progress is reported on a phase not on a deliverable asset, e.g., foundations, wiring, equipment, towers, etc.[73]

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[68] DR 418 and 419
[69] DR 254, 463, 464, 647, and 758
[70] DR 81 Attachment 3
[71] DR 758 Attachments 1 - 10
[72] DR 758

11. PSEG LI does not currently use industry accepted norms in schedule development.

- PSEG LI has tied project schedules to cost categories rather than the duration and sequence of activities. The scheduling procedure fundamentals state that "The project schedule will be inclusive of all project work scopes and will be consistent with the standard project WBS."[74]

- PSEG LI project schedules do not recognize increasing levels of detail. All known activities are listed at one level and are based on estimated labor hours, resource loadings and installation rates.

- Progress is monitored frequently but tracked and reported on a phase completion, not on deliverables, such as foundations, wiring, equipment, towers etc.[75]

- Reporting of progress is not reconciled against expenditures. Schedules are updated manually based on individual judgment.[76]

12. PSEG LI does not have a capital program and project quality assurance and quality control (QA/QC) program.

- PSEG LI does not have formal or specific QA/QC policies, procedures or standards applicable to capital projects.[77]

- While PSEG LI does not have specific policies or procedures related to QA/QC, PSEG LI states that QA/QC is "embedded" in the capital delivery process.[78] NorthStar's review of capital program and project delivery highlighted the following deficiencies:

    - PSEG LI's Program and Project Management Playbook identifies a "Quality Assurance & Control Programs Leader."[79] This position could not be found on PSEG LI's organization charts.[80]
    - The Playbook does not require the development of a QA/QC plan.[81] It advises the Project Manager to use QA/QC principles and methodologies during the project life cycle. QA/QC principles and methodologies are not identified.
    - PSEG LI did not develop any QA/QC plans or subsequent reports for any projects during 2016.[82]

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[73] DR 758
[74] DR 81 Attachment 3
[75] DR 758
[76] DR 447
[77] DR 67 and 81
[78] DR 73 and 379
[79] DR 475
[80] DR 2 Attachment 1
[81] DR 475
[82] DR 823 and 824

  - Policies and procedures provided by PSEG LI included: Project Authorization, Project Scheduling, Scope Management, Project Cost Management, and Project Execution Plan.[83] None of these documents specifically call out the necessity of QA/QC, address quality or indicate what specific activities should be conducted.
  - PSEG LI uses its design and construction standards as a form of QA/QC. The design and construction standards are developed to provide guidance to PSEG LI professionals in the development and modification to LIPA's facilities. Projects are evaluated for variances in design and cost, and while the standards can be updated for lessons learned, there is no formal update process.[84]

13. Capital program and project executive management oversight does not provide strong support for managerial functions.

- It is important to note at the outset, that NorthStar did not gain access to LIPA/PSEG LI executive management meetings until very late in the audit to observe processes such as high level oversight of capital programs and projects. NorthStar's findings and conclusions must therefore be qualified as such.[85]

- The URB Charter is explicit in its responsibilities related to budget. It does not extend its responsibilities to project management oversight.[86]

- The URB meeting books provided did not include consistent minutes tracking actions and considerations.[87] PSEG LI provided thousands of pages of URB documents archived since it became the LIPA Service Provider.[88] Capital Project Change Request forms are submitted to the URB for additional funding or timing and archived. However, meeting minutes, records discussion and formal acceptance or rejection of individual change requests were not recorded. It was not possible to determine whether PSEG LI adhered to its URB Charter that requires formal approval for project changes.

- Capital Project Change Requests submitted to the URB for approval lack detail and specifics regarding estimated funding increases that are necessary to understand the need for additional funding.[89]

- NorthStar's attendance at the Transmission and Distribution Project Coordinating Committee (TDPCC) and URB meeting observed management's focus on spending levels as compared to total budget. Individual projects were discussed after a budget issue was discovered and in the meeting attended, it was for approval for amounts already spent on three different projects.

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[83] DR 73

[84] DR 255, 454 and 456

[85] IR 42 – 45,187, 196 – 198

[86] DR 558

[87] DR 558

[88] DR 558 Attachments 1 - 75

[89] DR 558 Attachments 1 - 75

- Monthly progress report is retrospective and focus is dedicated to monthly spend. Total project budget to total spend over all years is not reported.[90]

- In 2016, with the exception of the advanced metering infrastructure (AMI) project, the URB approved all projects as requested indicating distance and lack of oversight.[91]

- NorthStar attended the URB meeting on September 25, 2017. Based on the one meeting attended, NorthStar found:

  - The meeting lasted less than 30 minutes.
  - Three projects with significant cost overruns were requesting additional funding:

    - Project overruns lacked justifications.
    - The money was already spent prior to the request.
    - URB approval was a formality and not a decision.[92]

14. Materials and equipment, transportation and other logistical support to capital programs and projects are effective. NorthStar did not observe project execution issues related to logistical support.

- Project estimates include provisions for major equipment and materials procurement.[93]

  - Project estimates include line items for various station equipment including circuit breakers, switches, poles, conduit.
  - Equipment rentals are included in detailed estimates such as rigging.
  - Civil construction items such as concrete, steel etc. are not included in the detailed estimates.
  - Specifically identified loaders for transportation are not identified in the detailed project estimates.

- The PSEG LI procurement organization is organized in seven categories responsible for a portfolio of products and services.[94] **Exhibit IX-8** provides the procurement organization categories and responsibilities:

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[90] DR 254
[91] DR 368
[92] IR 197
[93] DR 645 Attachment 10
[94] DR 185

Exhibit IX-8
Procurement Organization

Category	Staff	Responsibilities
1	3	Fleet Maintenance Gravel Sand and Dirt Lubes, Oils, Greases, Gases and Welding Supplies Personal Protective Equipment (PPE) Clothing and Footwear Street Lighting Transformer Oil Processing and Tanker Services Equipment Rentals and Purchases including vehicles Fleet Maintenance
2	2	Energy Efficiency Engineering Fire Protection Permitting and Testing Printing and Reproduction Publication, Subscriptions and Memberships Advertising Office Supplies and Equipment Professional and Legal Communications, Human Resources, Marketing
3	2	Construction Services Residential Underground Markout, Marine Service, Pole inspections and Reinforcement Paving and Concrete Services Vegetation Management Ground Maintenance, Storm Hardening Substation Spray Excavation Helicopter
4	3	Cable, Wire and Trench Instrumentation and Control Systems Meters Poles etc. Substation equipment Transformers, Capacitor Banks, Switchgear, etc.
5	1	Catering Health and Safety Training Inspections Transportation Services Water and Recycling Environmental Services Facilities Maintenance, Security
6	1	Maintenance, Repair and Operating Materials
7	1	Information Services, Software and Hardware

Source: DR 185.

- PSEG LI has a robust list of suppliers. In 2016, PSEG LI procured over $1.5 billion in products and services with over 1,100 suppliers. Products and service include electric operations engineering, construction, and materials, customer service operations and enterprise wide purchases such as insurance, payroll, and utilities.[95]

15. The use of in-house versus contracted services is appropriate.

- LIPA's first preference is to assign work to in-house and then to PSEG LI resources although consideration is given to PSEG LI workload.[96] Outside service providers are typically engaged by LIPA where there is a short-term need, positional conflict, lack of appropriate expertise or staffing in-house, or a regulatory need outside of PSEG LI's purview.

- Outside resources are used when workload prohibits assignment to either LIPA or PSEG LI resources or potential conflicts of interest are perceived.[97]

- PSEG LI stated that the use of in-house workforce versus contractor labor is typically driven by the type and duration of the work or when the organization does not have a specific skill set or is able to take advantage of economies of scale that would result in an overall savings of delivering the service.[98] However, decisions to contract are judgmental and PSEG LI does not perform formal economic analyses that would support its decisions to use outside labor. Outside services are addressed in greater detail in **Chapter X – Work Management and Outside Services**.

- PSEG LI has a good understanding of the work historically required to operate and maintain the T&D system and the capabilities of its internal staff.

- Outside resources are used to balance work load, satisfy deadlines and provide specialized services.[99]

16. Contractor and engineering bidding practices provide proper structure and guidance in procuring materials and services on behalf of LIPA.

- PSEG LI is authorized under the A&R OSA to perform procurement and rental functions on behalf of LIPA.[100]

- PSE&G has a centralized procurement function with seven dedicated resources at PSEG LI.[101]

- PSEG LI contracting and bidding practices are comprehensive and support competitive bidding.[102]

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[95] DR 183
[96] DR 47
[97] DR 47
[98] DR 83
[99] DR 83 and 366
[100] DR 71
[101] DR 2

- PSEG LI has developed one policy, one procedure, and a set of instructions. These documents in total provide:
    - Procurement Goals
        - Consistent approach
        - Improve cost and quality
        - Improve process efficiency
        - Manage and mitigate risk
        - Ensuring availability of materials and services
    - Procurement forms and work products
        - Purchase Orders – preferred method for materials and outside services
        - Contracts – method to be used when purchase orders are outside of the standard terms and conditions of a purchase order
        - Procurement Card – low-dollar transactions
        - Miscellaneous payment requests – low dollar transactions where Procurement Cards are not accepted
        - Expense reports – personal business expenses
    - Procurement Department involvement for all transactions over $5,000. This phased approach is supported by:
        - Detailed process flow
        - Roles and Responsibilities for the requestor, procurement, the supplier, accounts payable and the client.
    - Support of LIPA Policy including competitive bidding, written agreements, and inclusion of minority-owned/women-owned business enterprise (MWBE) standards.[103]

17. PSEG LI has an appropriate methodology for developing and administering contracts.

- Construction Management and Contract Administration (Procedure TD-CM-001-0001) provides the phases of construction contracts and the key milestones.
    - **Exhibit IX-9** provides the contract life-cycle and key milestones.
    - For each milestone, the procedure has: Roles and responsibilities and Required Activities to complete each milestone.
    - The procedure includes guidelines for writing the Scope of Work and Award Checklist.[104]

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[102] DR 158, 184, 185, 250 and 251
[103] DR 71

- PSEG LI requires a Contractor Evaluation Form upon completion of a contract. NorthStar reviewed a sample of contractor evaluation forms and found them complete and timely.

Exhibit IX-9
Contract Life-Cycle

Life Cycle Phase	Key Milestones
Request for Proposal (RFP) Development	1. Develop Scope and Execution Plan 2. Prepare Bid Documentation 3. Develop Strategy and Bid List 4. Develop and Issue RFP
Bid and Award	5. Respond to Contract Inquiries 6. Evaluate Bids, Select Contractor 7. Issue Contract Documents 8. Award Contract
Execute	9. Execute and Monitor & Control
Close-Out	10. Conduct Contract Close Out 11. Evaluate Contract Performance 12. Close-Out Project

Source: DR 476.

18. The A&R OSA assigns PSEG LI broad responsibilities for capital improvement, operation, maintenance and management of the T&D system but does not specifically obligate PSEG LI to performance levels or the effectiveness of activities that support these functions.

- Regarding program and project capital improvement, the A&R OSA does not address:
  - The establishment of a project management organization
  - Project management and controls standards
  - Project management tools
  - Project management reporting.[105]

- Project management services are necessary to protect both LIPA and the ratepayer from:
  - The potential adverse effects of poor project cost and schedule performance including overruns in cost and schedule;
  - The consequences 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;
  - The “hidden” cost of delays and the benefits of late projects;
  - The risks arising in general from a potentially litigious environment.[106]

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[104] DR 476

[105] DR 4 – A&R OSA Section 4.2.A.1

- There are no performance metrics directly related to capital project delivery.

- The Tier 1 metric, Capital Budget, measures dollars spent and compares this to 102 percent of budget. PSEG LI tracks the spend amount but does not determine what earned value LIPA received.

- The Line of Business Tier 2 metric, Capital Project Performance, measures two elements: forecast spend versus actual spend and number of milestones planned to number of milestones completed. However, this metric does not measure what is implied in the title. In particular, it does not:

  - Measure the quality of projects or the value of programs delivered for the amount spent
  - Measure specific project spend – it is portfolio based
  - Evaluate for adherence to schedule – it is portfolio based
  - Evaluate cost – as it is based on a month-ahead projection.[107]

- System reliability indices (SAIFI and CAIDI) reflect the long-term impact of capital improvements. While these indices are common for the industry, their usefulness as indicators for determining earned value is diminished due to the impact of storms, other externalities, and they are "lagging" indicators i.e., calculated and reported in retrospect of budgeting and expenditures.

- Near-term reliability drivers are vegetation management and equipment failure.[108]

19. PSEG LI does not perform internal audits of the capital improvement program as stipulated in the A&R OSA.

- Section 4.13 of the A&R OSA requires that, in each Contract Year, the Service Provider shall conduct an audit of the Capital Improvements made in the prior Contract Year. The audit shall measure the accuracy of the plant records, maps and maintenance databases concerning capital assets. Also, from time to time, the Service Provider must conduct a physical inventory of all capital assets.[109]

- PSEG LI claimed only one audit conducted during the audit period was related to Section 4.13 of the A&R OSA. An audit of "Fixed Asset Accounting," was completed March 7, 2016, and does not appear to satisfy the scope or requirements of A&R OSA Section 4.13. Highlights of audit observations included:

  - The plant accounting records are incomplete and inaccurate. Errors observed in the records pre-date the A&R OSA. It was noted that plant records are key to

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[106] http://www.projectcontrolsonline.com/Home/DefinitionandImportanceofProjectControls.aspx
[107] DR 18, 411, 600, and 963.
[108] DR 113
[109] DR 4

asset management activities and it has taken PSEG LI over two years to address the problem.

- The recording of new capital assets in the plant accounting system is not complete or correct.
- There are no controls to ensure integrity of data, no cross reference to SAP work orders (needed for project close out), and meter installations and removals are not captured.
- No processes or controls exist to review the impact on LIPA's financial statements for asset retirement obligations (ARO). An ARO is a cost carried on LIPA's balance sheets associated with the retirements of LIPA assets.[110]

- As a result of the Fixed Asset Accounting audit PSEG LI has developed a management plan to address the findings and stated that it will take several years to implement.[111]

D. RECOMMENDATIONS

1. Perform all policies, procedures and control functions that are currently and formally required.

   - PSEG LI should conduct all audits as required in the A&R OSA.
   - Adhere to formal document control policies and procedures.
   - PSEG LI should follow the PMP Playbook and its procedures.

2. The URB management processes and controls should be audited annually until the next DPS management audit, to confirm adherence to its charter and control policies and procedures.

3. Develop and implement procedures related to quality assurance and quality controls for capital programs and projects.

4. 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.
   - Assess the process used to develop and update estimates for completion.
   - 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 data true-up process.

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[110] DR 34, 35 and 834

[111] DR 834 and Attachments

- Review and document inflation and escalation factors and analyses used to predict project completion costs for each project estimate.
- 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.
- Formally document project cost reviews at each level of estimate in detail and at various stages of project completion as called for in Project Cost Management (Procedure TD-PM-002-0004).
- 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.
- Continuously verify the accuracy of estimates versus the actual project cost and maintain a record of updates to the estimating database.

5. Utilize a WBS in the initial phases of the project justification and conceptual estimating, and continue their refinement as the project progresses.

    - Develop well-defined work packages that can be used to track and measure project performance based on earned value.
    - 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 PSEG LI's accounting 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.
    - 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.

6. Formalize and incorporate contingency management in capital project cost estimating and cost management. Formally report the expenditure of contingency funds separately from project estimates rather than inflate total project budget amounts. It is critical that

reliable 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.

7. Define and report project management performance measures that focus on the effectiveness of cost estimation, earned value and schedule management. Project progress reports should be timely, and contain all information which is pertinent for their target audience. 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.

- 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.
- 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.
- Establish processes for systematic schedule preparation, review and analysis.
- 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.
- Highlight:

  - 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.

X. WORK MANAGEMENT AND OUTSIDE SERVICES

This Chapter provides the results of NorthStar's review of the work management processes of PSEG LI's Transmission and Distribution (T&D) Operations. It also addresses LIPA and PSEG LI's management of external service providers.

A. BACKGROUND

Work management is the application of information systems and management processes which focus on increasing work force performance through:

- Explicit work definition including quantification,
- Work planning and scheduling,
- Control and evaluation,
- Resource planning,
- Organization improvement, and
- Methods improvement.

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 improve 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 Publicly Available Specification 55 (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 X-1** below.

Exhibit X-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 and trend analyses 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 PSEG LI groups which perform construction and maintenance under the Amended and Restated Operating Service Agreement (A&R OSA), and were reorganized in August and September 2017.[1] Highlights of the reorganization included the following.

- Projects and Construction resources became part of Business Services including the functions of Project Management and Construction Management.

- A Project Management Office was established to include:
  - Estimating, Planning and Risk
  - Cost and Schedule
  - Permitting

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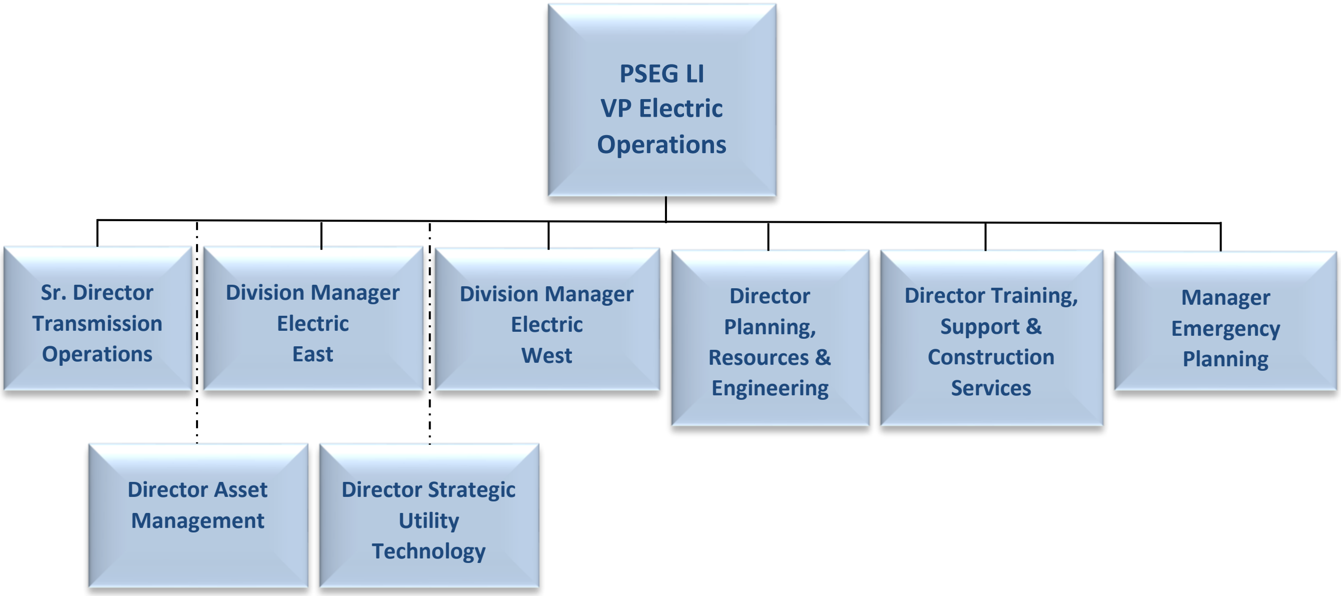
[1] DR 830

- Additional resources are planned for Project Management, Construction Management, project scheduling and project cost.

- The Projects and Construction function no longer includes Vegetation Management which stays within Electric Operations under the Director of Training, Support and Contractor Services.

The new organization structure is shown in **Exhibit X-2**. Dotted lines indicate PSEG LI functions that report directly to PSEG Services, New Jersey.

Exhibit X-2
PSEG LI Transmission and Distribution Operations



Source: DR 830.

Functions under the Director of Training, Support and Construction Services include:

- Process and Operations
- Technical Maintenance
- Line Academy / Corporate Training
- Public Works
- Telecom Systems / Radio Maintenance
- Vegetation Management

PSEG LI's T&D construction and maintenance personnel are assigned to two divisions (containing 12 workout locations): Western Division - in Queens/Nassau, Central (also in Nassau County) and Eastern Division - Western Suffolk and Eastern Suffolk.[2]

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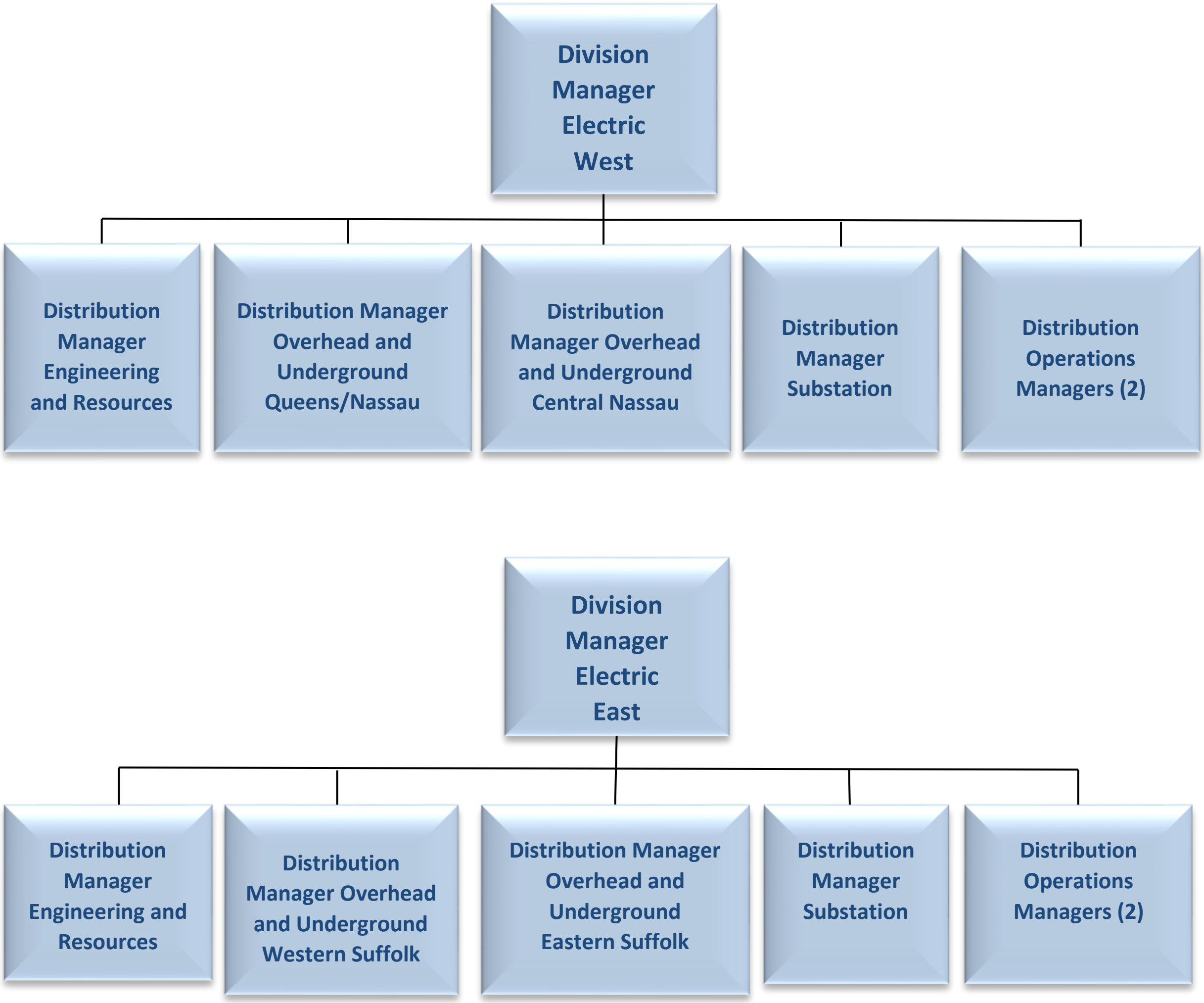
[2] DR 830

As shown in **Exhibit X-3**, each Division reports directly to a Division Manager (East and West), who reports to the Vice President of PSEG LI Electric Operations. LIPA's Vice President of Operations is responsible for oversight of the PSEG LI work in this area.[3]

Exhibit X-3
PSEG LI Construction and Maintenance Departments



Source: DR 830.

The PSEG LI Business Services organization is shown in **Exhibit X-4**.

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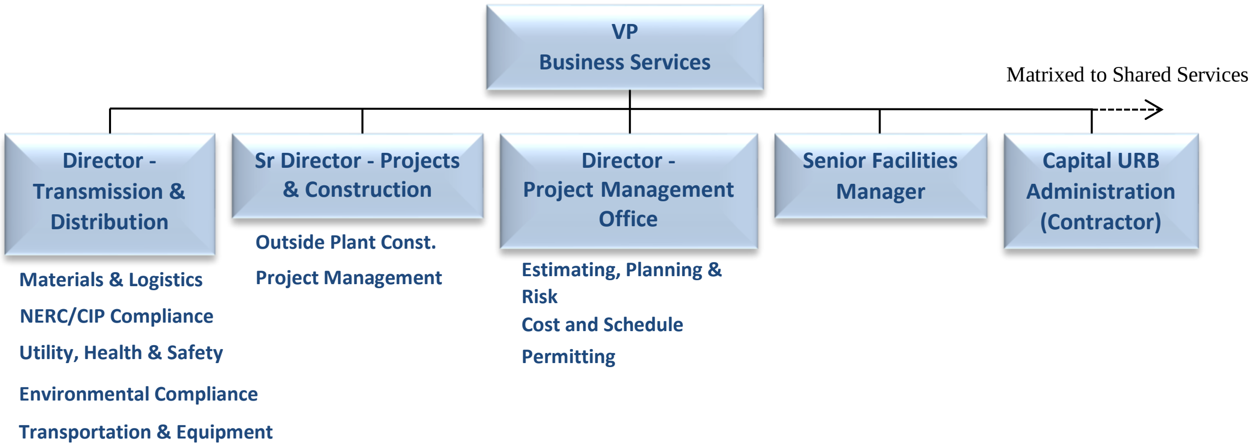
[3] DR 1

Exhibit X-4
PSEG LI Business Services Organization



Source: DR 830.

LIPA outsources the work involved in operating its T&D system through a service agreement with PSEG LI – the Service Provider. The outsourcing of such a major portion of core services requires the organization to have in place contracts, controls, and reporting mechanisms to ensure the provision of quality, reliable service to its customers.

B. EVALUATIVE CRITERIA

The audit of Work Management and Outside Services followed the list of baseline evaluative criteria provided by the DPS and an overall assessment of the effectiveness of the Authority's and Service Providers operations management.[4]

- Do work force management processes include work definitions, priorities, time durations standards, efficient scheduling, work order procedures, progress reporting, quality controls, performance measurements (productivity, utilization, lost/delay time trends, etc.)?
- Are work processes efficiently designed and implemented?
- Are programs and projects effectively converted into short-term and day-to-day work?
- Are work management systems used effectively to schedule and manage field crews, including transportation, equipment, and materials?
- Do work management systems appropriately interface with other key systems such the customer information system, dispatch, and outage management?
- Do existing systems provide timely, accurate information for LIPA/PSEG LI customers and other stakeholders?
- Does LIPA/PSEG LI use mobile technology for its field work crews and do existing systems provide timely and accurate information to customer contact personnel?
- Are work program and project schedules managed effectively on a day-to-day basis?

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[4] DPS RFP and Bidder's Package for Matter 16-01248, August 5, 2016

- Does information about rework, failures and repair history get translated into corrective actions, infrastructure aging analysis, and repair versus replace decisions in an effective and timely manner?
- Do the workforce and work management systems feed back into performance improvement opportunities?
- Are key performance indicators (KPIs) established by and reported to/by LIPA appropriate?
- Do existing systems and procedures provide adequate data to analyze work volumes and staffing requirements?
- Are existing SCADA, work management and outage management systems effectively used in identifying trends in workload levels, productivity, utilization and service levels?
- Do LIPA/PSEG LI measure and manage employee availability, utilization, efficiency, productivity and effectiveness in an appropriate manner?
- Are major workforce groups covered by work management systems to assign, execute, and control the work?
- Do excess work and process backlogs exist, and if so, does LIPA/PSEG LI have plans to eliminate them?
- Are assumptions documented when planning workforce requirements for new projects and continuous operations where history is inadequate to determine staffing levels?
- Do LIPA/PSEG LI use process and project performance data as a basis for continuous improvement? Do they track improvement in processes and workforce performance?
- Has LIPA/PSEG LI established appropriate decision-making processes and controls to assure that staffing levels are adequate (both in numbers and skills) for both day-to-day operations and emergencies to meet customer service, service quality, safety and reliability standards?
- Has LIPA's oversight of PSEG LI and the A&R OSA been effective? (Also addressed in Chapter III)
- Are operational policies and procedures consistently followed and do they meet applicable legal, regulatory and contractual requirements? (Also addressed in Chapter III)
- Are the decisions to use outside vendors for specific non-core services compared to in-house personnel, reasonable and regularly supported by analysis? (Also addressed in Chapter IX)

C. FINDINGS AND CONCLUSIONS

1. PSEG LI uses work management systems to plan, monitor and control the work of major work force groups although improvements must continue.

- PSEG LI's major construction and maintenance work groups are shown in **Exhibit X-3** and include:

  - Engineering
  - T&D Overhead and Underground (OH/UG)
  - Substation

  - Distribution Operations

- PSEG LI has started process improvement programs using the Six Sigma Program with Process Identification, Process Improvement and DMAIC (Define, Measure, Analyze, Improve, and Control) Teams to make improvements. Current functions include T&D materials management, tree trimming (performed by contractors), outage restoration and residential underground development but as yet do not include T&D construction and maintenance.[5]

- PSEG LI T&D is currently sponsoring an information technology (IT) project, the Computer Assisted Dispatch (CAD)/Work Management System project, specifically focused on enhancements to workforce management processes and systems. Planned deliverables between November 2018 and March 2019 include:[6]

  - Enhanced reporting of work progress and workforce productivity.
  - Improved efficiency, timeliness, and work completion data quality.
  - Improved dispatching and scheduling of work through electronic formats that eliminate paper formats.
  - Implementation of standard reporting templates to improve data quality.
  - Electronic time entry and approval to improve efficiency and accuracy of time reporting.
  - Increased crew efficiency through automated dispatching and intelligent routing, among numerous other enhancements.

2. Effective T&D construction and maintenance work management will require the explicit definition and quantification of work standards.

- Work definition is the description, documentation and communication of all activities needed to accomplish objectives, including a standard or estimate of resource requirements in man-hours. Work definition involves the determination of the work performed and allocation into discrete, measurable units.

- PSEG LI maintenance work in T&D and Substation includes work definitions (e.g., test and repair instructions) and historic time durations, but they are used infrequently as reference material.

- Work definitions that have been defined to date do not include man-hours required to perform the core work activities. Without quantification of resource requirements, the fundamental processes of work management including scheduling, work order procedures, progress reporting against tasks, quality controls, or performance measurements such as productivity, utilization, lost/delay time and trend analyses cannot be adequately determined.

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[5] DR 85

[6] LIPA/PSEG LI Fact Verification

  - T&D construction and maintenance workload quantification relies on institutional knowledge and historical relationships between budgets and resource levels. Discussion of the workload and any potential conflicts are continuously addressed and prioritized at the Planning, Resource and Engineering (PRE) management meetings.[7] From a system design perspective, the internal PRE engineering design managers meet and discuss the transmission and substation capital work load at the Engineering Work Plan meeting.
  - Workload quantification based on manager/supervisor estimates, historical relationships and discussions is insufficient to support continued improvement.

- PSEG LI's systems such as Microsoft Project, Oracle's Primavera P6 and the SAP work management module, can be used to support work management among the major construction and maintenance functions but PSEG LI does not currently utilize their full capabilities.

  - Microsoft Project is a project scheduling tool used to display program and project activities. Input to Microsoft Project is based on project operational needs and activity experience.
  - Primavera P6 is a scheduling and 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. Projects are input into P6 and loaded with milestone requirements based on need dates. Project Managers and various contributors provide input to the scheduling process – largely based on individual experience. Conflicted resources are reviewed and discussed for options to align with system requirements.[8]
  - SAP stores workload and budget data, producing work lists and Work Orders. It can report staffing information and produces weekly job status information but without work quantification, it does not provide reports on availability, utilization, efficiency, productivity or effectiveness.[9]

    - The SAP work management module is currently utilized to create, design, estimate, and complete electric work requests.
    - Jobs are generated within the system, capturing information including customer name, work location, type of work required, job status, constructing organization, internal and external contact information, and planned costs.
    - Users can query the system to identify work requests in their respective areas as well as pending items not yet assigned.
    - The construction organizations can obtain their work by querying the backlogs and printing out documents. Backlogs are defined as units of maintenance directly corresponding to the number of equipment units to be maintained.

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[7] DR 63
[8] DR 63
[9] DR 843

    Backlog is not expressed in terms of resource requirements or man-hours of work.
    - Completion dates and costs are captured within SAP for reporting and tracking.

  - The SAP work management module includes information on the assigned work, customer contact, completion date, equipment and materials but lacks additional work management information.[10]

- PSEG LI does not currently use a system or formal process to perform and integrate the work management processes described in **Exhibit X-1** (Work Management Process), to monitor productivity and optimize utilization of its workforce. Comparisons of actual work to targets and goals are based on units of activities performed. This lack of accurate productivity measures results in:

  - Limiting the value of any analysis done to identify future productivity gains.
  - Reducing the value of estimates used for capital and operations and maintenance (O&M) planning purposes.
  - Making in-house versus contractor analyses and decisions ultimately subjective.
  - Impacting 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.

- PSEG LI does not currently use workforce or work management systems to identify performance improvement opportunities.[11]

- PSEG LI is pursuing the implementation of a Computerized Maintenance Management System (CMMS) and an Asset Strategy Program to improve maintenance effectiveness but 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.[12] With respect to Planning, Resource and Engineering (PRE) work, PSEG LI responds to changes in workload but falls short of directly managing workload and required resources, stating:[13]

> To cover the base design workload, the PRE team has staff made up of engineers, designers, surveyors and real estate representatives, with the ability to flex up or down through the use of contractors and seconded employees. Where resource demands outstrip in-house and contractor/seconded employee design capabilities, projects and/or studies will be outsourced to professional Engineering News-Record (ENR) A/E (Architect/Engineering) firms for their engineering/design services. These outsourced projects and/or studies can range from a

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[10] DR 843, 844 and 845
[11] DR 7, 85 and 90
[12] DR 62, 63, 65 and 466
[13] DR 62

minor capital addition, new transmission circuit to a major new substation on a Greenfield site.

- In the absence of a comprehensive work management system, there is limited interface with other key systems such CAS, dispatch, SAP finance and accounting functions, and the OMS. Data for routine reports is dispersed in multiple applications, and the compilation of data for analytic and reporting purposes is a multi-step process lacking integration.

- A high level summary of PSEG LI's work management process deficiencies due to lack of defined work standards is shown in **Exhibit X-5**.

Exhibit X-5
Summary of Work Management Process Deficiencies

Process	Descriptions
1. Planning	Lacking formal definition and work quantification PSEG LI cannot assure resource availability to perform the work. Without workload quantification, analyses needed for analyses of planned versus unplanned work levels and backlog cannot be performed.
2. Work Preparation	Work quantification is needed to schedule resources like employee and/or contract work hours, access to the work site, material, equipment, vehicles, and other logistics.
3. Work Execution	Processes that support work assignment and completion expectations whether work is performed by employees and/or contractors.
4. Monitoring & Controlling	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.	

3. **Pass-through provisions of the A&R OSA do not provide PSEG LI incentives to improve work management methods. PSEG LI is incented to maintain expenditures within budget limits.**

- PSEG LI is responsible for management, operation and maintenance of the T&D system.[14] LIPA funds PSEG LI "Pass-Through Expenditures" for these services, including the cost of capital improvements, all goods and services including materials, supplies, spare parts, vehicles, purchased services, and other costs, and subcontractor costs.[15]

- Pass-through expenditures for labor costs are affected by work force utilization and productivity performance. If work force utilization and productivity are not controlled or improved over time, additional work load and labor costs may cause higher expenditures and rates.

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[14] A&R OSA Section 4.2

[15] A&R OSA Section 5.2

- The only two metrics contained in the Balanced Scorecard Performance Metrics that address the actual performance of T&D work are the "Staffing Levels – Permanent" and "T&D Preventive Maintenance", which simply targets a certain staffing level and number of work units to be completed in a year.[16] Furthermore, these two metrics are even less effective due to:

  - The Staffing Level is based on historical budgets and poorly developed estimates. Work contained in work plans is adjusted during the year and analysis against the original work plan is not measured.
  - The T&D preventive maintenance metric is based on a number of "units" that are generic – i.e., not formally defined or quantified in terms of resource requirements. Preventive maintenance units can be large or small and do not represent the entire workload portfolio. These "units" more often reflect the number of equipment units to be maintained.[17]
  - PSEG LI develops work plans and records the maintenance backlog, measures its own data, and reports to LIPA.

- NorthStar requested procedures that PSEG LI uses to establish staffing requirements for PSEG LI operational groups such as T&D maintenance and construction, field service, warehouse, workshops, fleet management/maintenance, purchasing, dispatch, including example forms and reports.[18] PSEG LI responded that staffing was proposed and ultimately recommended in the 2015 Three Year Rate Plan. The on-going staffing requirements are managed by the managers within the operational groups. When additional staffing is required, for example, for hiring above the rate of attrition because of long lead training requirements for key roles, the managers will make a request to their Directors. If the Directors determine that the additional staffing is required, the Director will seek approval from the Vice President of T&D Operations. Once approved by the Vice President, the Vice President reviews the staffing requirement with the President & Chief Operating Officer (COO). Upon Final Approval by the President & COO, the operational managers work with their Human Resources Business Partner to track the approval and follow the internal processes for hiring. An excel file is used by the T&D Business Partner to track staffing. In summary, PSEG LI staffing is therefore subjective.

- Significant levels of overtime warrant closer management attention to work force management systems and improvement programs. During 2014, PSEG LI operated on National Grid's SAP platform with National Grid contract services. As a result, 2014 overtime and straight time data is not readily available to PSEG LI and would require significant time, effort, and expense to obtain. Overtime levels for calendar year (CY) 2015 and CY 2016 are shown in **Exhibit X-6**.[19]

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[16] DR 411

[17] DR 390 and 613

[18] DR 87

[19] DR 846

Exhibit X-6
PSEG LI Overtime Charges for 2015 and 2016

Functional Area	Overtime Hours -2015	Straight Time Hours -2015	
New Jersey Asset Mgmt.	155	20,150	
Planning, Resources and Engineering	10,867	278,432	
T&D Services	21,628	187,908	
Overhead / Underground	200,010	613,046	
T&D Operations	129,260	349,934	
Projects and Construction	5,502	109,806	
Substation Protection	103,346	395,867	
Emergency Planning	324	21,043	
Total T&D	**471,092**	**1,976,187**	**23.8%**

Functional Area	Overtime Hours -2016	Straight Time Hours -2016	
New Jersey Asset Mgmt.	300	20,879	
Planning, Resources and Engineering	15,066	253,520	
T&D Services	34,365	176,181	
Overhead / Underground	229,895	631,868	
T&D Operations	178,228	380,368	
Projects and Construction	12,098	121,007	
Substation Protection	142,715	414,944	
Emergency Planning	589	22,976	
Total T&D	**613,255**	**2,021,744**	**30.3%**

Source: DR 846.

- Overtime is a practical necessity for utility services. However, industrial guidelines suggest that economic alternatives to overtime levels that exceed 15 percent exist and should be considered by management.[20]

4. **PSEG LI develops work plans which convert programs and projects into short term and day-to-day work for the operations, maintenance and support groups. However, PSEG LI's work plans require improvement and the development process documented.**

- PSEG LI uses Primavera P6 to generate short term work plans for OH/UG Lines and Substation activities.
  - The work plan is the primary tool for showing work priority and converting plans into short-term and day-to-day work. The work plan is also used as a project report.
  - 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.

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[20] As an example, US Bureau of Labor Statistics data, https://www.bls.gov/news.release/empsit.t23.htm

- Day-to-day scheduling is the responsibility of the Scheduling & Work Coordinator. Coordinators are located on-site in the East and West Divisions.[21] The Schedulers and Coordinators work for the Distribution Manager - Engineering and Resources in each Division's organization. Coordinator responsibilities include:

    - Coordinating resources (internal personnel, contractors, special equipment, vehicles, tools, etc.) and satisfy job requirements (switching & clearance requests, outage coordination, mark-outs, 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 schedule and for creating, prioritizing and managing daily work crew schedules.
    - Create and estimate work requests for emergency work as well as other types of work, as necessary, and 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.[22]

- Currently, PSEG LI's work plans do not:

    - Clearly prioritize projects,
    - Track productivity, or
    - Provide summary-level information regarding work force capacity utilization.

- There are no documented procedures for preparing work plans. The absence of procedures raises the risk of inconsistent planning.

5. PSEG LI does not measure employee availability, utilization, efficiency, productivity or effectiveness in an appropriate manner.

- PSEG LI does not currently track the productivity and utilization of the work force.

- 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. The reports do not include common work management measures such as:

    - **Standard Time** -- The labor (in man-hours) 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.

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[21] DR 2 and 830

[22] DR 2 and 96

  - **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.

- The Planning, Resource and Engineering organization participates in many meetings to share information across organizations.[23]

  - The primary meeting for Planning is the TDPCC (Transmission & Distribution Planning Coordinating Committee) meeting, which is held approximately every two weeks. LIPA, and PSEG LI Directors, Managers, and Engineers are given status updates regarding important current and future projects.
  - The primary meeting for Engineering is the Engineering Work Plan meeting is held approximately every two weeks. Project Managers, schedulers, cost associates and Engineering Leads all update the current and future project work plan. The work plan is then updated with the latest information and shared across the team.
  - Presently, scorecards maintained monthly are the performance measurement tools utilized to report on the status of planned T&D system maintenance.

- NorthStar requested T&D workforce management reports, particularly those that address availability, utilization, efficiency, productivity, quality, and effectiveness.[24] PSEG LI provided over three dozen reports showing the number of activities performed and a variety of overall performance measures. None of these reports addressed work force availability, utilization, efficiency, productivity, and quality or resource performance against targets.

6. PSEG LI’s current work management measures cover only a portion of the relevant work activity and do not include measures of productivity, efficiency, effectiveness, and utilization.

- NorthStar requested a summary of Electric Operations performance measures.[25] PSEG LI provided a list of over 60 measures purported to demonstrate effective achievement of business objectives. PSEG LI stated that a Key Performance Indicator is a measurable value that demonstrates how effectively the utility is achieving key business objectives. Organizations use KPIs at multiple levels to evaluate their success at reaching targets. However, not all organizational functions were covered in the list, measures lacked definitions and their relationship to business objectives was not always apparent.

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[23] DR 62

[24] DR 96

[25] DR 847

- Some management reports contain performance measures but functional coverage is mixed.

  - Performance KPIs for Electric Operations **management positions** could not be provided.[26]
  - KPIs can be found in a variety of PSEG LI management reports but these often cover **broad, functional areas** such as Transmission Operations, Distribution Operations, Substation and Telecommunications, Projects and Construction, and Services. Additionally, KPI measures are often generic such as illness, capital budget, customer satisfaction survey, and motor vehicle accident rate.[27]

7. **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 Planning, Resource and Engineering organization participates in many meetings to ensure the proper information is known and shared across organizations.[28] The primary meeting for Planning is the TDPCC meeting, held approximately every two weeks. LIPA, Directors, Managers, and Engineers are given status updates regarding important current and future projects. The Engineering Work Plan meeting held approximately every two weeks includes Project Managers, schedulers, cost associates and Engineering Leads to update the current and future project work plan. The work plan is then updated with the latest information and shared.

- Historical resource levels, expected capital budgets, and estimates of program work are used 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.
  - PSEG LI could not provide process documentation describing the preparation and use of histogram forecasts of workforce and contractor requirements.

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[26] DR 847

[27] DR 847 Attachment 1 – TD Metrics

[28] DR 62

8. PSEG LI has advanced its technology for mobile dispatch communications.

- The following organizations use Mobile Data Terminals (MDT) to help dispatch their work.[29]

  - Distribution Operations – to receive, update, and complete dispatched emergency/trouble work utilizing the Computer Assisted Dispatch (CAD) system.
  - Substation Operations – to document substation inspection data and manage Non-Reclose Assurance (NRA) switching requirements. Both utilize a web browser to capture data that is saved to an Oracle table.
  - Measurement Services – for daily work schedules for all Customer Office generated meter changes and upgrades and also Meter Engineering project work which includes Regulatory and special project meter installation and changes. Data is captured in CAD.
  - Collections & Meter Reading – for special reads and turn-on/turn-off orders utilizing CAD.
  - OH/UG Lines – to manage storm restoration work utilizing CAD.
  - Substation, Protection, & Telecommunications (SP&T) – to manage storm restoration work utilizing CAD.
  - Vegetation Management – uses "Esri Collector" on iPads to capture information on hazardous trees, damaged equipment and tree conditions found during transmission patrols, and to document vine issues for the Vine Management Program.[30]

- By March 2019, PSEG LI plans that all OH/UG Lines and Substation, Protection and Transmission work will be dispatched to those groups via MDTs.[31] The Emergency Planning group is working to finalize a major storm initiative to implement mobile technology to non-MDT equipped personnel (both internal and external) that will allow for the mobile assignment of work, provide the ability to remotely status work progress and allow for the electronic collection of data in the field via a smartphone, tablet, etc.

- 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 of pictures and documents. Supervisors have laptops with air cards for access to corporate applications like geographic information system (GIS) and email.

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[29] DR 381

[30] https://www.esri.com/en-us/about/about-esri

[31] DR 381

9. In-house versus outside resource decisions for non-core services are reasonable given PSEG LI staffing levels. Decisions to use contractors are not supported by formal economic analysis.

- PSEG LI described the rationale used for resource decisions and how tradeoffs are analyzed regarding in-house versus contractor labor. Economic analyses were not included in PSEG LI's response. T&D organizations compare their work needs to the existing workforce and if they determine insufficient labor, skill or equipment availability the decision is made to use contractors.[32]

- Non-core services as defined by LIPA/PSEG LI include the following:[33]

    - Catering Services
    - Facilities Maintenance (Office Furniture, Fencing & Gates, Painting, Heating, Ventilation, and Air Conditioning (HVAC) Services, Janitorial & Grounds)
    - Health & Safety & Training Services
    - Information Technology Services
    - Information Technology Software
    - Professional Services & Consulting (Legal, Financial. Credit & Collection, Communication, Human Resources, Marketing & Advertising, Translation Services, Power Markets)
    - Security Equipment & Services
    - Transportation, Freight & Small Package Services, Logistics

- Outside service providers are typically engaged where there is a short-term need, lack of appropriate expertise or staffing in-house, or a regulatory need outside of PSEG-LI's purview (e.g., certain Federal Energy Regulatory Commission (FERC) matters).[34]

- LIPA's first preference is to assign work to in-house or PSEG LI resources, although consideration is given to PSEG LI workload, potential conflict of interest and competing priorities.

- Potential conflicts can occur where PSE&G's corporate view is in conflict with the interest of Long Island customers, such as in energy resources and pricing. LIPA works with outside service providers to advance legal and stakeholder arguments in favor of lowering upstate capacity prices rather than relying on PSEG LI staff.

- Information Technology (IT) development and operational functions are normally performed by a third-party service provider.[35]

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[32] DR 366
[33] DR 414
[34] DR 47
[35] DR 83 and 366

D. RECOMMENDATIONS

1. Develop an integrated a work management system covering all PSEG LI operations, maintenance and construction resources that are based on engineered time standards and cover routine operations, repetitive maintenance activities, planned work, support requirements, and provide continuous feedback on workforce effectiveness. The system should be in an easy-to-use format expressed in man-hours, 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 work level versus resource histogram development and work plan process.
   - Enhanced methods to calculate workforce capacity and utilization.
   - Expanded workforce coverage in reports.
   - Documentation of processes for establishing workforce levels.
   - Documentation of criteria for adding contractor capacity.
   - Establish real time variance reporting for O&M and project costs.
   - Additional decision-making information to work plans.

2. Fill gaps in the current management information reporting and organizational reporting relationships to support an integrated work management system.

   - Develop formal reports on trends in work load levels, workforce productivity and utilization. The analysis of these trends identifies areas that are performing well, where improvements are needed, and is a foundation for the development of strategies to improve work force performance.

   - Establish formal processes to use work management data for annual resource planning as part of the annual business planning activities of PSEG LI operations and maintenance.

   - Develop formal work management practices for PSEG LI engineering and design functions. The work management systems should have appropriate system tools to support the various individual and distinct engineering functional processes. Elements that should be formalized include:

     - Scheduling
     - Prioritization and planning
     - Resource allocation and leveling
     - Performance measurement
     - Budget planning and control
     - Vendor tracking
     - Document/drawing control
     - Records management
     - Procurement management
     - Time reporting.

3. Develop overtime targets for PSEG LI operations and maintenance organizations based on economic analyses and verified industry norms.

4. Add KPIs for management positions. Review the design of monitoring and controlling reports to improve their usefulness.

XI. CUSTOMER OPERATIONS

This chapter provides the results of NorthStar's review of PSEG LI's customer operations systems, processes and controls, and compliance with associated state laws and regulations.

A. BACKGROUND

Customer Service Regulations

New York investor owned utilities are governed by the New York Codes, Rules and Regulations for the Department of Public Service (DPS) (16 NYCRR). Chapter I Rules and Procedures, Subchapter B provides procedures and requirements concerning consumer protections.

- Part 11 contains the Home Energy Fair Practices Act (HEFPA) and Energy Consumer Protection Act. HEFPA was enacted in 1981 to provide electric, gas and steam residential customers protection in the areas of services, billing and payment procedures. Subsequent amendments to 16 NYCRR extended HEFPA protection to consumers served by large private water companies (1986), incorporated the shared meter law (1995), and extended HEFPA protections to the transactions between residential customers and Energy Service Companies (ESCOs) (2002).[1]

- Part 12 provides Consumer Complaint Procedures.

- Part 13 - Rules Governing the Provision of Service by Gas, Electric and Steam Corporations to Nonresidential Customers, establishes rules governing the provision of service to non-residential customers.

In general, both Parts 11 (residential) and 13 (non-residential) address:

- The provision of service, including requirements for written applications, security deposits, denials of service, and timelines for initiation of service.
- Late payment and other charges, and deferred payment arrangements.
- Meter reading and billing, including estimated bills, backbilling and levelized (or budget) billing.
- Bill content and notification requirements.
- Termination, disconnection and suspension of service.
- Reconnection of service.
- Complaint handling.

Part 11 also includes additional procedures and special protections for residential customers threatened with disconnection due to lack of payment. These protections do not apply to non-residential customers. Part 11 protections include the following:

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[1] http://utilityproject.org/wp-content/uploads/2013/12/HEFPA-Chapter-Final-1231131.pdf

- **Medical emergencies** – If a customer demonstrates a medical emergency and obtains a certification from a medical doctor or local board of health, the utility may not terminate service for 30 days. A certificate may be renewed if the customer demonstrates an inability to pay his/her bill before the expiration of the initial certificate. Renewed certificates may stay in effect for 60 days or longer. After the expiration of a certificate or if the utility determines the customer has the ability to pay, it must send a termination notice 15 days prior to termination.

- **Life Sustaining Equipment (LSE)** – If a customer or resident of the household suffers from a medical condition requiring utility service to operate a life sustaining device (e.g., iron lung or dialysis machine), upon certification and the demonstration of inability to pay, utilities may not terminate service and must place special identification on the meter. The LSE certification remains in effect until terminated by the Department of Public Service.

- **Elderly, Blind or Disabled (EBD)** – If a customer is considered EBD and all other residents of the household are either EBD or under 18 years of age, the utility must make a diligent effort to call an adult resident of the household at least 72 hours prior to termination, disconnection, or suspension of service and attempt to make payment arrangements or other arrangements (e.g., payment by a governmental, welfare or private organization) to prevent termination. If the utility is unable to make arrangements with the customer, it must notify the local Department of Social Services (DSS) and wait at least 15 days for possible payment before termination.

- **Cold Weather Provisions** (November 1 to April 15) – During the cold weather season, utilities are required to take additional precautions for customers whose service is heat-related. The utilities must contact the customer or an adult resident at the premise by telephone or in-person at least 72 hours before the intended termination. Phone calls must be made once during normal business hours, and if unsuccessful, once during reasonable non-business hours. If the calls are unsuccessful, the utility must conduct an on-site personal visit. At the time of termination, the utility must again attempt to contact the customer in-person prior to termination. The purpose of the contact is to determine if the resident is likely to suffer a serious impairment to health or safety if the service is terminated. If the utility does disconnect service and the customer has not contacted the utility by 12 noon on the following day, the utility must immediately conduct a site investigation. If it determines a serious condition exists, it must restore service.

Exhibit XI-1 provides a listing of the Part 11 and 13 provisions.

Exhibit XI-1
Title 16 NYCRR Parts 11 and 13 Provisions

Part 11 (Residential Customers)		Part 13 (Nonresidential Customers)	
11.1	Purpose		
11.2	Applicability of rules	13.1	Applicability of rules and definitions
11.3	Applications for residential service	13.2	Applications for service
11.4	Termination or disconnection of residential service	13.3	Termination of Service
11.5	Residential service--special procedures		
11.6	Voluntary third-party notice		

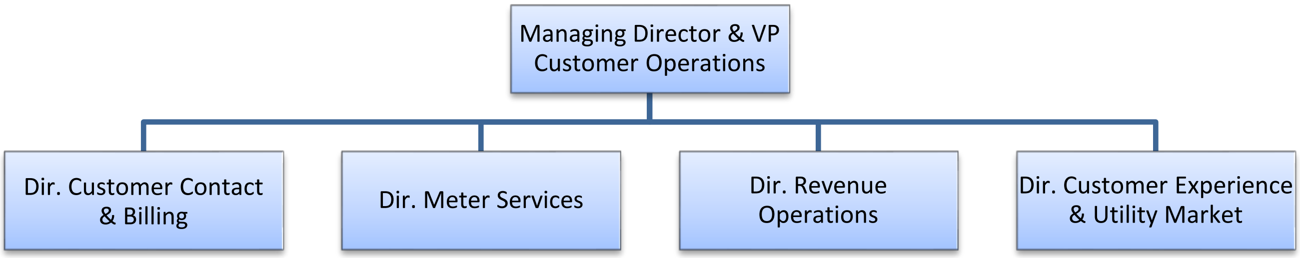
Part 11 (Residential Customers)		**Part 13 (Nonresidential Customers)**	
11.7	Service to entire multiple dwellings		
11.8	Service to two-family dwellings		
11.9	Reconnection of service	13.4	Reconnection of service
11.10	Deferred payment agreements	13.5	Deferred payment agreements
11.11	Budget or levelized payment plans	13.6	Levelized payment plans
11.12	Residential service deposits	13.7	Security deposits
11.13	Meter readings and estimated bills	13.8	Meter reading and estimated bills
11.14	Backbilling on residential accounts	13.9	Backbilling
11.15	Late payment and other charges	13.10	Late payment and other charges
11.16	Contents of bills	13.11	Contents of bills
11.17	Notification requirements	13.12	Notice requirements
11.18	Emergency disconnections of residences	13.13	Disconnection without notice
11.19	Inspection and examination of utility apparatus	13.14	Inspection and examination of utility apparatus
11.20	Complaints to the utility	13.15	Complaint-handling procedures
11.21	Emergency hotline		
11.22	Waiver	13.16	Severability
11.23-29	(Reserved)		
Shared Meter Regulations			
11.30	Definitions		
11.31	Commission's designee		
11.32	Service to shared meter account		

Source: 16 NYCRR.

Organization and Operations

Under the terms of the Amended and Restated Operating Service Agreement (A&R OSA), PSEG LI is responsible for the performance of customer service functions. LIPA provides oversight and works with PSEG LI to develop performance metrics. PSEG LI maintains a call center in Melville, New York, 12 customer offices/service centers and over 60 authorized pay locations.[2] **Exhibit XI-2** provides the PSEG LI Customer Operations Organization.

Exhibit XI-2
PSEG LI Customer Operations Organization



- Contact Center
- Back Office Billing
- Workforce Planning
- Customer Technology & Training
- Billing System/LI Choice

- Meter Reading
- Meter Testing, Repair & Installation
- Meter Shop
- Field Collections
- Planning & Analysis

- Customer Offices (12)
- Back Office Collections
- Revenue Integrity
- Payment Processing
- SOX Controls and Revenue Reporting

- Customer Marketing
- Customer Experience (Customer Intelligence and DPS Complaints)
- Major Accounts
- Economic Development

Source: DR 2 Attachment 1, IR 55, 60, 61 and 65.

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[2] DR 975 Attachment 1

Meter Reading and Billing

There are three basic steps in utility customer billing: meter reading, bill calculation, and bill printing/production. These three steps are time-critical processes as there are typically 20 billing cycles in a month. PSEG LI's billing cycle has four key events:

Day 1 – Meter Read and Verification
Day 2 – Bill Calculation
Day 3 – Bill Printed and Mailed
Day 25 – Payment Due.[3]

PSEG LI uses three types of meters to obtain customer usage data:

- Manual - 97 percent of the meters are manually read. PSEG LI meter readers enter the reads manually into a hand-held Itron meter reading unit. In special circumstances, when a residential meter is not accessible, an automatic meter reading (AMR) device (also called "recorder receiver technology") is installed. The hand-held unit receives the read automatically when the meter reader walks by the meter. There are approximately 17,000 AMR meters in the residential sector.[4]

- MV-90 – MV-90 is an Itron-manufactured meter that records usage information on intervals such as 15 minutes. The meters connect with the utility via telephone or internet. The meters are necessary for utility load research programs and real-time pricing rates. MV-90 meters are also installed for commercial meters that are inaccessible to the meter reader. There are 922 MV-90 meters installed in the commercial sector.[5]

- AMI - LIPA and PSEG LI have committed to the implementation of an advanced metering infrastructure (AMI). AMI is an advanced technology which enables two-way communication between the utility and the customer. The meter provides real time energy use, utility conditions and billing information. Currently less than three percent of all installed meters are AMI.[6]

Eighty-four percent of PSEG LI customers receive monthly bills, but most meters are only read every other month. The intermediate month's usage is estimated based on previous usage. **Exhibit XI-3** provides details on PSEG LI's meter reading and billing frequencies.

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[3] DR 108
[4] DR 219
[5] www.Itron.com
[6] DR 219

Exhibit XI-3
Meter Read and Billing Frequency

	Number of Customers						
		Monthly Billed					Total
	Monthly Read	Percent	Bi-Monthly Read	Bi-Monthly Read and Billed	Percent	Subtotal	
Residential	98,794	10%	770,362	157,902	90%	928,264	1,027,058
Non-Residential	72,261	59%	22,278	27,680	41%	49,958	122,219
Total	**171,055**	**15%**	**792,640**	**185,582**	**85%**	**978,222**	**1,149,277**

Source: DR 218.

Most PSEG LI bills are produced using a batch process in the Customer Accounting System (CAS). CAS is a custom mainframe application developed in 1975 which has been modified over time to increase functionality and address user requirements. CAS serves as the system of record and comprises the bulk of the meter-to-cash process.[7] The Enhanced Billing Option (EBO) was implemented in 2001 to ensure compliance with the NYPSC's Uniform Business Practices and Single Bill Orders for ESCOs and Utilities. EBO is used for summary billing, ESCO billing, and allocation of payments.

Approximately 285 of PSEG LI's accounts must be billed manually because they involve non-standard rates, special tariff conditions or specialized contracts that are not supported by CAS or EBO. The majority of these accounts are associated with cogeneration customers and the Recharge New York program, through which the New York Power Authority provides low-cost energy to customers as part of an economic incentive rate. These bills are calculated using an off-line Microsoft Access billing system. The billed revenue is manually entered into CAS and the customer receives a manually-developed PSEG LI bill that is almost identical to a CAS bill. A limited number of customers receive "Cycle 21" bills, that are processed outside the CAS system.[8]

Call Center Operations and Complaint Handling

PSEG LI is responsible for handling customer complaints, including those arising from billing concerns, service problems, rate issues or other matters, such as claims.[9] The PSEG LI call center and customer offices are the primary points of contact for customer service-related inquiries and complaints. Customer Service Representatives (CSRs) follow a standard escalation procedure to work towards resolving customer complaints. At times, a customer may not be satisfied with the proposed resolution and ask to speak with a manager. Customers may also ask to speak to, or indicate that they will be contacting, a PSEG LI executive, the Better Business Bureau (BBB), DPS or LIPA. If unable to address the customer's concerns, CSRs are directed to immediately engage the Call Center Supervisor to speak with the customer.

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[7] DR 196

[8] DR 213, 214, and 215

[9] Per the Shared Meter Law only LIPA can make a decision regarding shared meter assessment.

Complaints Referred to the Department of Public Service (DPS)

The DPS requests that customers first try to resolve the complaint with their utility; however, if the customer feels they are unable to get satisfactory help from the utility, they may file a complaint with the DPS' Office of Consumer Services (OCS). There are three levels of investigations: 1) the initial decision on the complaint; 2) an informal hearing or review; 3) an appeal of the informal hearing or review.[10]

In 2002, the OCS developed its Quick Resolution System (QRS) to facilitate timely resolution of customer concerns. Under the QRS, complaints to the DPS are initially forwarded to the utility for resolution. These complaints are classified as QRS. A QRS case is reclassified as a Standard Resolution System (SRS) if a customer is dissatisfied with PSEG LI's attempt to resolve the issue and contacts the DPS within 60 days from the date the QRS was closed, or if PSEG LI does not respond to Executive Correspondence within 5 days. The DPS investigates SRS complaints. The OCS manual, "*QRS: A Service Providers Guide to Handling Consumer Complaints Filed with the NYSDPS*" outlines requirements for handling QRS and SRS complaints. For a QRS complaint, the utility investigates the complaint, responds to the customer and notifies OCS of the resolution. For an SRS, DPS investigates and responds to the customer.

If a customer or utility is not satisfied with the results of the DPS investigation it may request an informal hearing or review. Requests should be made within 15 days of the DPS' initial decision. If the utility and the customer are unable to settle the complaint, the DPS hearing officer will make a decision. If the customer or utility disagrees with the decision rendered in the informal hearing or review, the customer or utility may appeal the decision within 15 days. For the investor-owned utilities, appeals are decided by the PSC; however, PSEG LI appeals are decided by LIPA.[11]

The DPS compares the complaint response performance of the New York utilities using two metrics:

- **Complaint Rate** – At first all complaints are recorded and forwarded to the utility for resolution directly with the customer. These are noted as initial complaints (QRS) in the table titled Complaint Activity of New York's Major Utilities in the OCS' Monthly Reports on Consumer Complaint Activity. If the customer informs the OCS that the utility failed to satisfy their complaint the matter is escalated for further handling and investigation by staff and is noted as escalated complaints (SRS). Both numbers are converted into a complaint rate which allows the reader to compare performance regardless of the size of a company's customer base. The escalation rate is a measure of how successful a utility is in satisfying their customer upon receipt of an initial complaint made through the Office of Consumer Services. The 12-month complaint rate is often used as one of several customer service measures that may be taken into consideration when staff monitors the quality of customer service delivered by an individual utility.

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[10] DPS involvement with the LIPA customer complaint process is relatively new. Prior to 2014, DPS had no jurisdiction or involvement in LIPA customer complaints. As part of the LIPA Reform Act, the DPS Long Island Office was authorized to review, investigate and make recommendations to LIPA or PSEG LI for the resolution of customer complaints.

[11] NYS DPS Guide to Filing Complaints about your Regulated Utility Service, DR 97

This rate represents the average number of escalated complaints received per month per 100,000 customer accounts.[12]

- **Customer Service Response Index (CSRI)** – CSRI reports on the level of customer service and responsiveness delivered by each utility. The CSRI is based on four metrics.

  - The Consumer Satisfaction Metric (CSM) is a ratio of the number of initial complaints to the number of escalated complaints in the reporting month.
  - The Complaint Response Time Metric (CRM) is the average number of days it took the service provider to respond to initial complaints closed in the reporting month.
  - The Escalated Complaint Response Time Metric (ERM) is the average number of days it took the service provider to respond to escalated complaints closed in the reporting month.
  - The Pending Case Metric (PCM) is the average age of all cases awaiting response, determined on the last day of the reporting month.

B. EVALUATIVE CRITERIA

Billing

- Do customers receive accurate and timely bills and are internal goals appropriate?
- Does PSEG LI have processes to determine if customers are on the proper rate classification or if customers qualify for a different rate? Are customers notified if they qualify for or should be on a different rate?
- Are PSEG LI's bill estimation procedures reasonable and are adequate steps taken to minimize estimated bills?
- Does PSEG LI have an adequate system of internal controls to address the requirements of the New York State Codes, Rules and Regulations of the Department of Public Service (16 NYCRR) Parts 11 and 13 as it relates to billing?

Complaints

- Are PSEG LI's call complaint resolution processes adequate and effective?
- Does PSEG LI have appropriate processes for handling customer complaints and inquiries that have not been resolved and/or have been referred to DPS?
- Does PSEG LI file timely, accurate and quality responses with DPS in regards to escalated complaints and appeals?
- Does LIPA have a formalized process to handle complaints and inquiries that have not been resolved?

Call Center and Customer Operations

- Are existing customer information and customer accounting systems used to support customer service operations adequate and effective? Do customer systems adequately support technical business needs and processes (including interfaces with other systems

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[12] January 2018, Office of Consumer Services Monthly Report on Consumer Complaint Activity (http://www3.dps.ny.gov/W/PSCWeb.nsf/All/448C499468E952C085257687006F3A82?OpenDocument)

and external service providers, compliance with state laws and regulations, and the achievement of customer service goals?

- Is the call center's performance as measured by average speed of answer (ASA) and abandonment rate consistent with service level requirements and industry practice?
- Does PSEG LI have processes and systems for analyzing and reflecting feedback from customers?
- Do PSEG LI's quality control and customer service staff training processes and procedures comply with state laws and regulations?
- Do other departments provide the call center with relevant, accurate information on a timely basis?
- Does PSEG LI have an adequate system of internal controls to address the requirements of the Home Energy Fair Practices Act (HEFPA) and Energy Consumer Protection Act (16 NYCRR Part 11)?
- Does PSEG LI have an adequate system of internal controls to address the requirements of the Rules Governing the Provision of Service by Gas, Electric and Steam Corporations to Nonresidential Customer (16 NYCRR Part 13)?

C. FINDINGS AND CONCLUSIONS

Billing

1. Customers receive accurate and timely bills.

- PSEG LI has numerous controls related to accurate meter reading and calculation of bills. In particular:
    - Controls are built into the meter readers' Itron hand-held devices:
        - High and low read tolerances are programmed in the Itron units for each meter. When a meter reader enters a read outside of tolerance an alarm sounds and the meter reader must re-enter a read.
        - The Itron devices do not contain data on past consumption or demand to prevent meter readers from entering reads without actually reading the meter.
    - Supervisors conduct walk-alongs and field audits. The purpose of a walk-along is to evaluate a meter reader's training and performance. Topics addressed can include knowledge of the equipment, knowledge of the route, and safety.
    - Each day PSEG LI performs verification tests on a sample of bills before they are generated by CAS. PageCenter (a reporting application) develops three reports containing all necessary billing determinants from the recent batch of meter reads. PSEG LI calculates the bills manually and compares with the PageCenter reports.[13]
    - PSEG LI has a 16-week process for implementing annual tariff changes. The process includes coordination between the IT programmers, the bill presentation specialists, and rate and pricing personnel. The process involves multiple phases of data entry, coding, testing, and verification.[14]

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[13] DR 106 and 198

[14] DR 199

- LIPA's external auditor, KPMG LLP, conducts annual audits of LIPA's financial statements. The audit scope includes testing the controls on the accounting and billing systems. In 2016, KPMG tested a sample of customer bills and customer billing reports and did not report any controls issues related to customer revenue.[15]

- In 2015, PSEG LI performed an internal audit of meter multipliers. A meter multiplier is applied to a meter read to calculate actual consumption and demand. Meter multipliers are specific to the meter and most meters do not have a multiplier. PSEG LI Internal Audit observations included:

  - Procedure documentation was not current – Meter services has updated the documentation.
  - Late submittal of field documents – Meter services manager will enforce timely submittal of field documents.
  - CAS data error – One meter in the sample had an incorrect multiplier in CAS. This was due to late submittal of field documents.[16]

- An internal audit was performed on the customer billing process in 2015. This audit scope included: evaluating the design and effectiveness of processes and controls to ensure accuracy, completeness and validity of billing calculations, timely handling of billing exceptions, and authorized changes to CAS. The auditor provided a "clean opinion," indicating there were no adverse findings.[17]

- There are parameters in CAS to validate bills and to identify any anomalies or errors. Failures in validations (e.g., high/low consumption, incomplete field orders, or the meter read data does not match to billing system) result in the display of error messages and the creation of an "Error Memo" which is sent to the Exception Memo Management System (EMMS). [18]

  - PSEG LI maintains 158 exception codes. Exceptions may be informational or may require manual review and/or adjustment to ensure bill accuracy.
  - PSEG LI investigates billing exceptions to determine whether a re-read is necessary or whether the bill may be released.

- In 2016, approximately 18 percent of billing exceptions were related to high bill codes.[19]

  - PSEG LI uses a 300 percent tolerance above last year's daily usage to trigger a high bill exception.[20]
  - PSEG LI uses a number of techniques to resolve high bill exceptions, including:

    - Review of account notes.
    - Contacting the customers.

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[15] DR 197

[16] DR 503 Attachment 6

[17] DR 35 and 197, Telephone call with PSEG LI Internal Audit on 1/25/18 10:00 a.m. PST

[18] DR 106

[19] DR 222

[20] DR 223

    - Send out for re-read.[21] PSEG LI sends over ten percent of high bill complaints to the field for investigation.[22]

- NorthStar reviewed a sample of high bill exception cases and found:

  - High bill exceptions have 26 possible causes. For the first half of 2017, PSEG LI generated 16,850 high bill exceptions. Approximately half were informational in nature and subsequently released for bill generation:
    - 2,500 were identified as bad reads,
    - 3,200 cases were determined to be increased usage, and
    - 1,500 were identified as various meter issues.[23]

  - PSEG LI attempted to contact the customer in over 30 percent of the cases.[24] Most exceptions are informational, so no contact is necessary.
  - In cases where the customer could not be reached by telephone, PSEG LI sent the customer a letter notifying them of the potentially high bill.[25]
  - PSEG LI uses a number of methods to resolve high bill exceptions. The most common include:
    - Releasing bills identified as informational exceptions,
    - Re-reads,
    - Obtaining customer reads,
    - Generation of a bill estimate, and
    - Testing of a meter.

- NorthStar tested both batch and manual customer bills for accuracy and found them to be correctly calculated. NorthStar's selection included the most common rate codes and a sample of each type of manual bill. NorthStar's review confirmed the following:

  - Energy rates match rate schedule,
  - Service and meter charges match published rate schedule,
  - Demand rates match rate schedule,
  - Demand is recorded on bill,
  - Meter constant is recorded,
  - Resulting demand form meter constant is correct,
  - Calculation of consumption,
  - Correct number of days,
  - Energy charges were correct,
  - Power supply charge was correctly calculated, and
  - Proration of power supply charge across months.[26]

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[21] IR 101
[22] DR 222
[23] DR 564
[24] DR 106 and 565
[25] DR 565
[26] DR 203, 216, 481 and www.psegliny.com

- An outside vendor provides bill printing and mailing services for PSEG LI batch bills. From January 2014 through April 2017, bills were mailed one day late on ten occasions. This represents an on-time performance of 98.75 percent.[27]

- NorthStar reviewed PSEG LI's manual billing process and found manual bills are scheduled to be billed monthly and that PSEG LI issued bills in a timely manner.[28]

2. **PSEG LI has basic, but appropriate, internal goals for customer billing, which are typical of the industry. PSEG LI has met its 2016 performance targets for billing exception cycle time, number of long term estimates, percent AMI-measured energy, and actual meter read rate. Based on November 2017 data, PSEG LI will meet its performance targets for all four metrics in 2017.**

- Meter reads and bill issuance are critical components of the billing process. PSEG LI has A&R OSA performance goals that address these functions:

  - Billing Exception Cycle Time,
  - Long Term Estimates,
  - Percent AMI-Measured Energy, and
  - Actual Meter Read Rate.[29]

- The Billing Exception Cycle Time metric measures the percent of billing exceptions completed with three days, an indicator of bill timeliness. PSEG LI has consistently achieved this metric. The target has gotten more aggressive each year, while the number of exceptions has declined. A decline in exceptions can result from a number of factors including increased accuracy, stable consumption patterns, or a reduction in the parameters used to generate exceptions. **Exhibit XI-4** shows PSEG LI's performance.

Exhibit XI-4
PSEG LI Billing Exception Cycle Time Metric Results

Year	Total Number of Exceptions	Number of Exceptions Completed in 3 Days	Percent Completed in 3 Days	Metric Target
2013 (National Grid)	414,102	88,075	21.3%	None
2014	283,820	250,938	88.4%	61.5%
2015	314,631	283,847	90.2%	66.1%
2016	239,965	224,371	93.5%	70.7%
2017 (through November)	197,395	180,742	91.6%	90.0%

Source: DR 411, 962 and 991.

- As shown in **Exhibit XI-5**, PSEG LI has generally met its performance targets for the Long Term Estimates, Percent AMI, and Actual Meter Read Estimates metrics.

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[27] DR 220 Attachment 1

[28] DR 481

[29] DR 411

Exhibit XI-5
PSEG LI Target and Actual Performance

Year	Long Term Estimates		Percent AMI		Actual Meter Read Rate	
	Target	Actual	Target	Actual	Target	Actual
2014	14,300	15,522	N/A	N/A	96.8%	97.1%
2015	3,718	3,497	N/A	N/A	97.1%	91.9%
2016	2,747	2,411	13.6%	17.0%	97.4%	97.8%
2017 (through November)	2,190	1,842	33.8%	36.1%	97.5%	97.6%

Source: DR 411, 962 and 991.

- The Long Term Estimates metric measures the number of customer bills with three or more consecutive missed reads.[30] PSEG LI has consistently achieved this target since 2015.
- Percent AMI measures the ratio of the total energy measured by AMI divided by the system-wide delivered energy. PSEG LI met this metric in 2016 and 2017.
- Actual Meter Read Rate is the ratio of the number of meters read to meters scheduled to be read. PSEG LI has come close, but did not meet this metric in 2015 and 2016. It is NorthStar's experience that, although Actual Meter Read Rate is commonly measured, not many utilities use this metric for incentive compensation. Actual Meter Read Rate was moved to Tier 2 in 2016; it is not used for incentive compensation.

3. LIPA/PSEG LI comply with PSC precedent regarding rate code assignments.

- In Case 10-G-0028, the Commission determined that NY utilities did not have the burden to annually review customer usage and unilaterally transfer it to any rate schedule for which it might be eligible.[31] According to the Commission's May 25, 2017 determination:

> "Unless otherwise stated in the tariff, a gas utility does not have the duty to monitor customers' usage and unilaterally assign them to any service classification or Rate Schedule for which they are eligible, because monitoring gas usage and switching customer accounts to eligible rates can be prohibitively expensive and very difficult, if not impossible. Indeed, the Commission previously found that monitoring the gas usage of a large number of customers, as here, is impossible.
>
> This … is also consistent with Public Service Commission rate design assumptions. In designing rates, the Commission presumes that utilities do not monitor the usage of each individual customer. Customers are in a better position to know if they should be reclassified because they know their future needs, have notice of tariffs, as filed with the Commission, and receive monthly bills that contain their rate classification and usage data, among other things."

- Residential customers must complete an application for service. The application may be submitted on the telephone, online, or in person. LIPA's Tariff identifies a residential customer as:

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[30] The majority of LIPA's customers are read bi-monthly so three consecutive missed reads might result in a meter not having an actual read for over 8 months.

[31] January 26, 2016 and May 25, 2017 Determinations in Case 10-G-0028 (www.dps.ny.gov)

  - An individual, separately metered, single-family dwelling.
  - An individual, separately metered, flat or apartment, or other building where each dwelling is separately metered under an account in each occupant's name.
  - A two-family or three-family dwelling on a single meter, when the customer of record resides in one of the dwellings.
  - Portions of a two-family or three-family dwelling used in common when connected to the meter or any apartment.[32]

- Customers that are not residential are deemed non-residential, and are placed on general service rates. The non-residential application is a written process. Through the application process, PSEG LI assists the customer in determining the appropriate rate based on the type of business, installed equipment, customer plans, and perceived needs. PSEG LI has three primary general service rate codes. **Exhibit XI-6** provides a comparison of the three most common general service rate codes.[33]

Exhibit XI-6
LIPAGeneral Service Rate Codes

Rate Element	Small Commercial Rate Code 280	Large Commercial Rate Code 281	Large Commercial, Multiple Periods (Secondary Voltage) Rate Code 285
Energy Use	<2,000 kWh per month	Over 2,000 kWh per month	Over 2,000 kWh per month
Demand	<7 kW	7 kW to 145 kW	>145 kW in any two consecutive months
Meter Charge per day	$0	$0	$2.50
Service Charge per day	$0.36	$1.72	$8.15
Demand Charge per kw per month	$0	Summer/Winter $13.18 /$11.97	Peak/Shoulder/Off-peak $23.53/$5.60/$0
Energy Charge per kWh	Summer/Winter $0.0938/$0.0749	Summer/Winter $0.0285/0.0136	Peak/Shoulder/Off-peak $0.0312/$0.0199/$0.0048

Source: LIPA tariff and https://www.psegliny.com/files.cfm/rates-comm.pdf.

- PSEG LI manages changes to the assignment of general service rate codes as follows.

  - When a customer exceeds the maximum energy or demand thresholds for two consecutive months, CAS generates a billing exception. The customer is advised through a letter of the mandatory rate change.
  - If a customer remains below the minimum energy or demand threshold for twelve consecutive months, CAS automatically puts a notice on the customer bill regarding the option to change rates. **Exhibit XI-7** provides a typical notice:[34]

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[32] LIPA Tariff, LIPA/PSEG LI Fact Verification.
[33] LIPA Tariff and https://www.psegliny.com/files.cfm/rates-comm.pdf
[34] DR 200

Exhibit XI-7
Rate Option Notice on Customer Bills

PSEG LONG ISLAND

We make things work for you.

Visit www.psegliny.com

MESSAGE CENTER

Visit us at www.psegliny.com/commercial and learn about online options and other programs designed for businesses that can save time, save money and save energy, so you can concentrate on your success.

We're working harder than ever to provide energy for a growing Long Island and customers like you are helping us improve our performance. Thank you. Your credit rating is tops with us!

Rate Change Option: Your energy usage and recorded demand have been below the levels that require you to be on your current rate, 281 (Commercial, Large). As a result, you qualify for the potentially more economical Rate 280 (Commercial, Small), which has no separate demand charge. Your rate will only be changed at your request. To discuss options, please call 1-800-966-4818.

Source: DR 190.

- There are potentially significant costs to the customer associated with being on a less beneficial rate. NorthStar analyzed the impact of assigned rate codes on customer bill amounts using various sets of usage patterns. **Exhibit XI-8** provides the results of the analysis.

Exhibit XI-8
NorthStar Bill Analysis General Service Rate Codes

Customer Usage	Rate Code 281 Bill (General Service, Large)	Rate Code 280 Bill (General Service, Small)	Difference
Summer 1,800 kWh, 6 kW, 30 days	$189.36	$186.48	$2.88
Summer 1,000 kWh, 3 kW, 30 days	$125.82	$108.40	$17.42
Summer 375 kWh, 1 kW, 30 days	$81.18	$47.40	$33.78

Customer Usage	Rate Code 285 Bill (General Service, Large, Multiple Periods)	Rate Code 281 Bill (General Service, Large)	Difference
Summer – 30 days Peak/Shoulder/Off 140/110/110 kW 30,000/7,500/5,000 kWh	$5,533.40	$3,151.15	$2,382.25
Summer – 30 days Peak/Shoulder/Off 100/80/80 kW 20,000/8,000/5,000 kWh	$4,070.80	$2,333,00	$1,737.80
Summer – 30 days Peak/Shoulder/Off 80/50/50 kW 12,000/5,000/5,000 kWh	$3,088.50	$1,768.30	$1,320.20

Note: Excludes Power Supply Charges.
Source: LIPA 2018 Tariff, https://www.psegliny.com/files.cfm/rates-comm.pdf, and NorthStar Analysis.

- PSEG LI does not analyze rate conformance regularly. In 2014, following the transition from the prior service provider, PSEG LI conducted three point-in-time studies assessing the correct application of general service rates:
  - Rate 280 Transfer-Up Study – identified 2,791 customers (5 percent of the rate class) requiring a mandatory change from Rate 280 (General Service, Small) to Rate 281 (General Service, Large).
  - Rate 285 Transfer-Down Study - identified 617 customers (10 percent of the rate class) with an option to change from Rate 285 to Rate 281 (General Service, Large).
  - Rate 281 Transfer-Down Study – identified 1,015 customers (2 percent of the rate class) with an option to change from Rate 281 (General Service, Large) to Rate 280 (General Service, Small).[35]

- While PSEG LI does not proactively perform studies for customers to determine the proper rate classification, it will, upon customer request, analyze the customer's usage against available rates.[36]

4. PSEG LI has reasonable procedures for estimating bills.

- When PSEG LI is unable to obtain a scheduled meter read it estimates usage to develop a bill. An estimated bill is generated by CAS when the meter reader enters a "skip" in the Itron hand-held meter reading device during a normal scheduled meter read.[37]

- PSEG LI has different estimating procedures based on the type of account: Residential Non-heating and Small Commercial; Residential Heating; and Commercial Demand Meters.[38] PSEG LI outlines its estimated bill procedures in LIPA's Schedule of Tariffs on leaf numbers 95 and 97.[39]

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[35] DR 200
[36] DR 201
[37] DR 207
[38] DR 207 Attachment 1
[39] www.lipower.org

- CAS calculates Residential Non-Heating and Small Commercial customer estimated bills four different ways:

    - The preferred estimation method is "same time last year". A bill is compared against an actual read for the same period the previous year. Previous year's usage is divided by the number of days in the billing cycle and then multiplied by the number of days in the current billing cycle.
    - If the read from the "same time last year" was estimated as well, CAS prepares an average of the daily use of the previous year's estimate and the daily use from the following read if it was an actual read. This average is multiplied by the number of days in the current billing period.
    - The third method is a simple average of the historical daily usage of the full history of the account multiplied by the number of days in the current billing cycle.
    - The fourth method is used when there is no history. A fixed daily usage value is multiplied by the number of days in the billing cycle. Currently the residential base value is 30 kWh/day for most rate schedules and 22.44 kWh/day for small commercial customers.[40]

- The methodology used to estimate Residential Heating bills depends on the season:

    - For summer months (June 1 - September 30), the "same time last year" method is used.
    - For winter months:

        - A daily usage for the summer months is determined based on historical usage.
        - The historical winter months' usage is reduced by the base daily amount of usage.
        - The remainder is divided by heating degree days, yielding a weather factor.
        - The weather factor is applied to actual heating degree days yielding consumption that is weather-related.
        - The daily base usage is multiplied by the number of days in the billing cycle and added to the weather related consumption.
        - When there is no history available, PSEG LI assigns a base usage and weather factor based on the previous occupant and weather.[41]

- PSEG LI makes multiple attempts to read a commercial demand meter before an estimated bill is rendered. There is a two-day period between the initial read and the bill print. When an estimated bill is necessary, CAS estimates the bill with the "same time last year" methodology. However, if the previous year was estimated, PSEG LI manually intervenes and obtains a reading.

5. PSEG LI has taken steps to reduce the use of estimated bills due to meter access difficulties. While the total number of estimated bills has not varied significantly, the number of consecutive estimates has decreased.

- Since 2014, PSEG has estimated an average 18 percent of its bills annually. While the total number of estimated bills has not varied significantly, the number of consecutive

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[40] DR 207 Attachment 1

[41] DR 207

estimates has decreased. **Exhibit XI-9** provides the number of meters having consecutive estimates from 2014 through 2016.

Exhibit XI-9
Number of Consecutive Estimated Bills

Year	Number of Consecutive Estimated Bills		
	Two	Three	Four
2014 [Note 1]	24,943	10,735	5,860
2015	48,099	17,314	8,814
2016	31,516	12,357	5,493

Note 1: 2014 includes only 10 months of data (March through December. January and February typically have higher than average number of estimated bills).
Source: DR 207.

- To minimize the number of estimated bills due to meter access issues, PSEG LI:
  - Obtains an appointment to read the meter.
  - Permits the customer to provide meter reads.
  - Installs AMI meters.
  - Notifies customers of pending non-access fees.
  - Charges non-access fees. 16 NYCRR permits a monthly fee ($25 for residential customers and $100 for commercial customers) beginning at the greater of more than four consecutive estimates (monthly meter reads) or eight months (bi-monthly meter reads) if a customer does not make an arrangement with PSEG LI. In 2016, PSEG LI assessed 5,330 consecutive estimate fees.[42]

- In 2016, Long-Term Estimates (LTE) was added as an A&R OSA metric. An LTE is defined as missing three consecutive meter reads. In 2015, there were 3,497 LTEs. In 2016, the goal was to have fewer than 2,747 LTEs. PSEG LI reported 2,411 LTEs in 2016 and met this metric.[43]

6. Customer bills are clear and generally contain the information required by 16 NYCRR Parts 11 and 13. NorthStar's testing identified only minor exceptions.

- PSEG LI initiated a bill redesign project in March 2014. The redesigned bill was put into production in August 2016.[44] NorthStar reviewed the previous bill format and the current bill format and found:
  - The new format is $8^1/_2$" x11"; the previous bill was smaller.
  - The payment stub is now at the bottom of the bill as opposed to the top.
  - The new bill introduced red banners and bold fonts to highlight key information as opposed to the black and white format used before.
  - The front of the new bill has improved visibility of contact information, the next meter read date and the payment amount and due date.

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[42] DR 207
[43] DR 411
[44] LIPA/PSEG LI Fact Verification

  - The back of the new bill provides meter read information and has an improved description of how to pay information.[45]

- NorthStar tested a sample of bills to determine if they met the 16 NYCRR content requirements listed in **Exhibit XI-10**.

Exhibit XI-10
16 NYCRR Parts 11 and 13 Tested Bill Content Requirements

Residential Bill Content	Non-Residential Bill Content
Residential Bills must include: • Name • Address • Account Number • Dates of present and previous readings • Type of reading (actual or estimated) • Amount owed for latest period • Payment due date • Penalty for late payments • Credits from past bills • Any amounts owed and unpaid from previous bills **Must also include:** • Service classification • Billed demand • Meter multiplier constant • Charges and credits that are adjustments to the base charges **Budget Billing** • Type of plan • Total year's budget billed • Dollar amount billed for tariff items • Debit and credit balances **Payment instructions** • How bill may be paid • Distribution offices • Authorized office or a payment agency	**Non-Residential Bills must generally include:** • Includes only services performed and itemizes charges • Can provide messages and other information **All Bills** • Name of corporation • Location of office and one more business offices • Service classification • Name of customer, account number and address • Start and end date of billing period • Quantity of service billed, unit of measure, explanation of calculations and factors and disclosure of tariffs • Due date • When late charges are assessed • Explanation of abbreviations • Telephone number **Cycle Bills** • Registered demand • Date of latest payment • Assessed late payment charges • Next read date **Metered Service Bills** • Indices used to calculate • Read source • Meter Multiplier

Source: 16 NYCRR Parts 11 and 13.

- NorthStar's testing of customer bills identified minor exceptions:
  - Commercial customer bills do not include a definition of "kW." 16 NYCRR Part 13 requires an explanation of all abbreviations displayed on the bill. PSEG LI acknowledges the oversight and agrees to include a definition on the next revision to the bill format.[46]
  - Residential time-of-use bills do not include the late payment date line. 16 NYCRR Part 11 requires the display of the late payment date. PSEG LI acknowledges the oversight and agrees to include this information on the next revision to the bill format.[47]

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[45] DR 105

[46] DR 203, 204 and 571

[47] DR 203, 204 and 570

- Residential bills do not include the location of local payment offices or a listing of authorized offices or payment agencies. 16 NYCRR Part 11.16d requires that bills include "an explanation of how the bill may be paid, including one or more local distribution utility offices at which it may be paid, and a statement that bills may be paid at other authorized offices or payment agencies."[48]

- **Exhibit XI-11** provides the information displayed on residential customer bills on methods to remit payment.[49]

Exhibit XI-11
Bill Payment Options Shown on PSEG LI Residential Bills

It's Your Bill. How You pay is Your Choice.

Online or Phone

Make a payment anytime from a checking or savings account with My Account or our automated telephone services or pay by text.

www.psegliny.com
Text PSEGLI (773454)
1-800-490-0025

DirectPay

Automatic payments from your bank. Skip check and stamps. Never worry about due dates.

www.psegliny.com

Credit Card

Pay your bill with a credit card online or by phone (fee applies).

www.psegliny.com
1-800-490-0025

In Person

Payments are accepted at any customer service center or authorized locations.

Locations at
www.psegliny.com

By Mail

Payments to:
PSEGLI
PO Box 888
Hicksville NY 11802-0888

Send correspondence to:
PSEG Long Island, PO
Box 9083, Melville, NY
11747-9083

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Source: DR 203.

- PSEG LI provides the web address, www.psegliny.com, to obtain a listing of service centers and authorized locations. PSEG LI believes this complies with 16 NYCRR Part 11.16(d). PSEG LI further explains that there are 12 service centers and 26 authorized agencies in the service territory and that listing them on the bill would be voluminous.[50]
- The language of 16 NYCRR Part 11.16(d), while not explicit, implies that the location should be provided for "one or more local distribution offices". No physical address is provided for a walk-in location.
- Customers paying bills in person are often cash customers with lower financial means and access to credit cards, internet, computers, and online banking. Seniors might also be limited in their online access. The offering of a web address does little for some of these customers.

7. PSEG LI's balanced billing program meets the requirements of 16 NYCRR Parts 11 and 13.

- As required by 16 NYCRR Part 11.11 and Part 13.6, PSEG LI offers its residential and non-residential customers a budget or levelized billing payment plan option. The budget billing equalizes annual electricity bills over 12 months. The purpose of budget billing is to prevent peaks and valleys in customer bills and allow customers to have a flat monthly

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[48] 16 NYCRR Part 11
[49] DR 105, 203 and 204
[50] DR 105, 203, 204 and 569

bill for household budgeting purposes. A description of the program and the eligibility requirements are contained in LIPA's Tariff on leaf number 108.[51]

- Overall, PSEG LI has had good customer acceptance of the balanced billing program - 41 percent of residential and 8 percent of commercial customers are enrolled, but the numbers have declined in the past few years. **Exhibit XI-12** provides the number of enrollees by year.

Exhibit XI-12
Budget Billing Enrollment

Year	Total Residential Enrollments	New Residential Enrollments	Total Commercial Enrollments	New Commercial Enrollments
2014	N/A	31,149	N/A	2,241
2015	442,527	18,761	9,303	1,659
2016	420,370	15,794	8,823	340
2017 through March	417,277	4,273	8,711	102

Source: DR 205 and 206.

- NorthStar tested a sample of levelized bills for compliance with the requirements of 16 NYCRR Part 11.11 and Part 13.6**.** Specific requirements are listed in **Exhibit XI-13**.

Exhibit X-13
16 NYCRR Parts 11 and 13 - Budget Billing Summary of Requirements

Part 11 - Residential Budget Billing	Part 13 - Non-Residential Budget Billing
• Utilities must offer residential budget billing • Amounts to be based on 12 months of customer billing history if available, if available, or else 12-months premise history, or an estimate • Amounts require regular reviews • Commission approval of levelized payment plans required	• Utilities must offer non-residential budget billing to eligible customers • Non-residential levelized payment plans (budget billing) require the following: – Methodology for establishing the levelized payment amount – Policy and methodology for comparing actual cost to levelized cost. True-ups must occur not less than twice and not more than 4 times annually – Customer bills must provide accounting of total of levelized amount paid relative to actual costs

Source: 16 NYCRR Parts 11 and 13.

- NorthStar found:
  - PSEG LI offers a balanced billing plan to residential and commercial/industrial customers. The plan is promoted in bill inserts, the web, the Integrated Voice Response (IVR) system and on social media.[52]
  - The methodology for balanced billing is based on 12 months of billing data when available. Otherwise 12 months of history for the premise is used. If no data is available PSEG LI estimates usage based on similar facilities.
  - The balanced amount is reviewed and true-ups are performed annually. This is an automatic process in CAS.

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[51] www.lipower.org

[52] DR 205

  - As the balanced billing program is included in LIPA's Tariff.[53]

8. **PSEG LI is in compliance with 16 NYCRR Parts 11 and 13 in the administration of backbilling.**

   - Backbilling or delayed billing refers to assessing a customer for usage and charges that were not charged on the contemporaneous bills. They fall into two categories: customer non-culpable and customer culpable.

     - Non-culpable refers to situations the customer is not at fault. Instances include a broken meter, advanced consumption, different meter multipliers, slow meter, fast meter, and incorrect account setup.
     - Culpable refers to situations where the customer is at fault such as theft of service or fraud.

   - PSEG LI's backbilling policies are provided in LIPA's schedule of tariffs on leaves 101-103 and 116. **Exhibit XI-14** compares the major requirements of 16 NYCRR Parts 11 and 13 related to backbilling to the LIPA Tariff.[54]

Exhibit XI-14
16 NYCRR Parts 11 and 13 Backbilling Requirements

Part 11 Residential Backbilling	PSEG LI Tariff
First Utility Bill	
May backbill for unbilled service up to 6 months if there is no customer culpability and utility is culpable. PSEG LI must bill customer within four months of learning of situation.	Leaf 101 IV.B.4.b(1) – Complies Leaf 100 IV.B.4.a(1) - Complies
May backbill up to 24 months for unbilled service if there is no customer culpability and no utility culpability	Leaf 101 IV.B.4.b(3) – Complies PSEG LI indicates no record of this situation ever occurring.
Part 11.14 is silent on backbilling when customer has culpability	Leaf 101 IV.B.4.b(5) – Stipulates up to 6 years
Subsequent Bills	
May backbill for unbilled service up to 12 months if there is no customer culpability and utility is culpable	Leaf 102 IV.B.4.c(1) – Complies
May backbill up to 24 months for unbilled service if there is no customer culpability and no utility culpability	Leaf 102 IV.B.4.c(2) – Complies
Part 11.14 is silent on backbilling when customer has culpability	Leaf 101 IV.B.4.b(5) – Stipulates up to 6 years Leaf 103 IV.B.4.c(4) – Complies
Special Conditions	
Utility must offer a payment plan for adjustments greater than $100 if the customer in not culpable	Leaf 101 IV.B.4.b(4) – Complies Leaf 103 IV.B.4.c(3) – Complies
Adjustments for greater than 12 months shall be billed within 4 months of resolution of the billing dispute	Leaf 102 IV.B.4.c(2) – Complies Leaf 100 IV.B.4.a(1) – Complies
Adjustments for any unbilled service greater than 12 months shall include a reason for the adjustment included with the bill	Leaf 102 IV.B.4.b(6) – Complies

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[53] DR 205 and www.lipower.org

[54] DR 208 and www.lipower.org

Part 13 Non-Residential Backbilling	PSEG LI Tariff
Customer culpability includes knowledge or reasonably should have known the utility bill was incorrect	Leaf 116 V.A.2.f(1) - Complies
Catch-up bills are considered backbills if the bill exceeds 50 percent of the estimated bill	Not addressed
May backbill for wrong service classification if application was inaccurate or misleading	Leaf 100 IV.B.4.a(3) - Complies
Must offer a payment plan if backbill is twice the original bill or $100 or more – the greater of the two	Leaf 102 IV.B.4.b(6) – Complies
Utility must render a backbill for unbilled service within 6 months of identifying a situation	Leaf 100 IV.B.4.a(2) – Complies
Utility must render a revised backbill for overbilling within 2 months of identifying a situation	Leaf 103 IV.B4.d(2) - Complies
When utility is culpable, limited to 12 months of backbilling unless customer is culpable. PSEG LI must bill a customer within six months of learning of situation.	Leaf 101 IV.B.4.b(2) – Complies Leaf 102 IV.B.4.c(1) – Complies Leaf 100 IV.B.4.a(2) - Complies
When there is no culpability by customer or utility, limited to 24 months	Leaf 101 IV.B.4.b(3) – Complies Leaf 102 IV.B.4.c(2) – Complies PSEG LI indicates no record of this situation ever occurring.
Written explanation for any backbill that includes more than one billing period	Leaf 102 IV.B.4.b(6) – Complies
Part 13.9 is silent on backbilling when customer has culpability	Leaf 101 IV.B.4.b(5) – Stipulates up to 6 years

Source: 16 NYCRR Parts 11 and 13, LIPA Tariff June 1, 2017 and IR 221.

- The 16 NYCRR Part 13 finds a nonresidential customer culpable for incorrect billing if the customer had knowledge or should have had knowledge that the bill was incorrect. PSEG LI has identified these situations as when the customer has added load to the service and never notified the utility.[55]

- PSEG LI backbills for up to six years when a customer is culpable for unbilled services. 16 NYCRR Parts 11 and 13 do not provide a time limitation. PSEG LI uses six years based on the reasonable availability of records.[56]

Complaints

9. With the transition to PSEG LI, customer complaint and call handling processes have improved significantly.

- Prior to the transition to PSEG LI as the Service Provider, the call center's focus was on the speed of answer calls and average handled time (AHT), with an AHT standard of 300 seconds (i.e., five minutes). The CSRs' performance was tied to AHT. As a result, many CSRs would end calls within five minutes by transferring the calls to another queue or indicating that customers would need to be called back.[57]

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[55] IR 221

[56] IR 221

[57] IR 22, 55 and 95

  - In 2015, PSEG LI removed AHT as a metric for the CSRs, in order to allow them to better focus on addressing the customer's needs.[58] PSEG LI also eliminated the call-back database.[59] PSEG LI continues to track AHT, but uses it as a discussion metric.[60]
  - In 2016, PSEG LI added metrics for hold time and the percentage of appeals (escalated calls).[61] For 2017, the emphasis is call quality increased (as measured through a call monitoring quality assurance process) and the hold time minimum was reduced from 30 to 20 seconds.[62]

- Both the CSRs that work in the call center and the representatives that work in PSEG LI's walk-in offices follow documented Standard Escalation and Escalated Complaint Resolution Procedures which are clearly defined.[63] The new escalation process, established in April 2016, was designed to reduce customer complaints and ensure calls are handled consistently. The procedure also applies to complaints received through social media.[64]

  - CSRs are instructed to listen attentively, empathize, and attempt to understand and resolve the issue. If the customer insists on escalation the CSRs are to reach out to their supervisor or another supervisor. If none are available, the customer is to receive a call back within two hours. If the supervisor is unable to resolve the issue, the escalation process continues.
  - If a customer insists on speaking with an executive or the DPS, they are to be immediately referred to management.
  - Procedures posted on an internal website remind CSRs that they are required to first dial into a queue for supervisor assistance and are instructed not to tell a customer that supervisors are not available without trying first.[65]
  - The current call quality performance evaluation considers whether CSRs follow the proper procedure for escalating a call.
  - Training also emphasizes a warm transfer (when the agent who is currently speaking with the caller speaks with the new agent before the call is transferred) if a call must be escalated to a supervisor.[66]

- Following the 2014 transition, PSEG LI modified the CSR hiring processes to better screen candidates, eliminated the use of temporary agents, and improved its CSR training program. The training time increased by three weeks, mentors work with the trainees to assist them as they are taking calls during the training, and there is an increased emphasis on other areas of the business.[67]

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[58] IR 95, DR 581
[59] IR 55
[60] DR 581
[61] DR 581
[62] DR 581
[63] NorthStar Review of DR 97 Response PSEG LI
[64] DR 97_Response PSEG LI
[65] DR 580 Attachments 7 and 8
[66] IR 97
[67] IR 55 and 97

- As shown in **Exhibit XI-15**, PSEG LI's complaint handling has improved over time as measured by the OCS metrics.

Exhibit XI-15
PSEG LI Complaint Performance

	2014	2015	2016	2017
12-month Escalated Complaint Rate	1.1	0.9	0.2	0.2
Range of All Electric and Gas Utilities	0.1 to 1.8	0.1 to 1.4	0.1 to 1.5	0.0 to 1.5
December CSRI	7.1	8.9	9.5	10

Source: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/448C499468E952C085257687006F3A82?OpenDocument.

- Contact center customer satisfaction has improved over time as measured by after call surveys. Customers contacting the call center are asked to participate in a brief survey at the end of the call. **Exhibit XI-16** shows the residential and commercial survey results. In each year PSEG LI exceeded the A&R OSA targets. Residential survey targets were 67 percent satisfaction in 2014, 71.5 percent in 2015 and 83.3 percent in 2016. Non-residential survey targets were 47.6 percent satisfaction in 2014, 71.5 percent in 2015 and 83.3 percent in 2016.[68]

Exhibit XI-16
Customer Satisfaction – After Call Survey

Source: DR 18.

- Other measures of customer satisfaction have similarly improved as shown in **Exhibit XI-17**. In all cases, performance has improved each year and exceeded A&R OSA targets.

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[68] DR 18 Attachments

Exhibit XI-17
Customer Service Performance

Metric	2014		2015		2016	
	OSA Target	Actual	OSA Target	Actual	OSA Target	Actual
JD Power Customer Satisfaction Survey (Residential)	542	571	565	584	588	610
JD Power Customer Satisfaction Survey (Business)	551	595	576	631	602	689
Personal Contact Survey	83.7%	90.7%	85.5%	92.9%	87.3%	94.6%
Average Speed of Answer	79	54	66	35	53	24
Abandonment Rate	3.8%	2.6%	3.4%	1.4%	3.0%	1.1%

Source: DR 18 and Attachments.

10. While PSEG LI has adequate processes for handling complaints referred by the DPS, there are opportunities for improvement.

- In January 2014, PSEG LI implemented a process to ensure customer complaints were handled in accordance with LIPA Tariff and DPS requirements. PSEG LI's Customer Relations Department (Customer Relations) is the primary point of contact for customer complaints referred by DPS, a PSEG LI Executive, PSEG LI Government Relations, the Better Business Bureau (BBB), rate consultants and social media.[69]

- When PSEG LI receive a DPS QRS or SRS case, the general process is as follows:

  - Case is assigned to a Customer Relations representative.
  - Customer is contacted.
  - Account is notated, and collections action suspended, if necessary.
  - Investigation is conducted.
  - Customer is contacted, and the complaint is addressed.
  - Completed case and any supporting documents are provided to the DPS in accordance with DPS' Office of Consumer Services guidelines.[70]

- The process is well-documented in a process flow diagram with specific tasks assigned to responsible groups.[71]

- The quality of the case file documentation needs improvement.[72]

11. PSEG LI's database to track complaints referred by the DPS is inadequate as it does not track all requisite information to confirm compliance with DPS requirements and internal and external reporting.

- In accordance with the DPS process, once the DPS opens a case, PSEG LI must:[73]

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[69] DR 774
[70] DR 97 PSEG LI
[71] DR 774
[72] DR 595, DR 596, DR 770

  - Contact the customer within two hours if the matter is related to a collections issue or a service outage.
  - Contact all other customers as soon as possible, but no later than the close of the next business day.
  - Provide the customer with the name and phone number of a designated representative who will be available to assist the customer with this matter or any future matter.
  - Afford the customer protections under 16 NYCRR Part 12, including Part 12.3 which requires the continuation of utility service, providing all monies owed to the utility have been paid, except those monies which the customer is disputing.
  - Provide a timely report to OCS identifying all cases that were completed and indicating whether the case was resolved to the customer's satisfaction
  - Resolve complaints within prescribed time frames:
  - Provide a detailed written resolution to any Consultant Case within 14 days of receipt as instructed in the case details.
  - Resolve the matter with the customer within the specified time:
    - QRS – Response to DPS required within 14 days.
    - SRS– Response to DPS required within 10 days.
    - Executive Correspondence (complaint received by a public or government official) – Response to DPS within 5 days.[74]
    - Consultant Case – Response required within 14 days.
  - Classify closed cases using the following definitions:
    - Resolved Case – the service provider discussed the matter with the customer and reached a resolution with the customer that appears to have been accepted by the customer.
    - Unresolved Case – the service provider was unable to reach a resolution that was acceptable to the customer.
    - Resolved and Closed, Complete Resolution Pending Completion of Work – the case which has been closed but full resolution will not take place until some time in the future.

- PSEG LI currently tracks DPS complaints in the Complaint Tracking System (CTS).

  - In 2014, when PSEG LI began to provide service to LIPA, it tracked customer complaints using "Remedy," a former National Grid System.
  - In 2015, PSEG LI implemented the Microsoft SharePoint-based CTS to track complaints and inquiries from DPS and other sources.

- The CTS system was not designed with the DPS requirements in mind. As shown in **Exhibit XI-18**, CTS does not allow tracking of all information necessary to ensure compliance with the DPS requirements.

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[73] Complaint Handling Guide for Service Providers (QRS Guide) http://www3.dps.ny.gov/W/PSCWeb.nsf/All/FA05AA0D1F13FED085257687006F3A81?OpenDocument

[74] Complaint Handling Guide for Service Providers (QRS Guide) http://www3.dps.ny.gov/W/PSCWeb.nsf/All/FA05AA0D1F13FED085257687006F3A81?OpenDocument

Exhibit XI-18
NYS DPS QRS/SRS Requirements vs CTS Database

DPS QRS Requirement	Does CTS have Necessary Field?	
Case Classification and Deadlines	**Y/N**	**Comments**
▪ Must contact the customer within two (2) hours if the matter is related to a collections issue or a service outage	Y	There is a Date of Contact field which may be formatted to included time.
▪ Must contact all other customers as soon as possible but not later than the close of the next business day	N	There is no separate time field.
	N	No Complaint Type field to indicate if collections, service or billing issue.
Designated Contact		
▪ Must provide the customer with the name and phone number of a designated representative who will be available to assist the customer with this matter or any future matter	N	No field to indicate if designated Representative and phone number has been communicated to customer.
Written Response Requirements		
▪ Must provide a detailed written resolution to any Executive Correspondence within five days of receipt as instructed in the case details	N	No field.
▪ Must provide a detailed written resolution to any Consultant Case within 14 days of receipt as instructed in the case details	N	No field to indicate if written response applicable, relevant written response deadline, and if completed.
Case Resolution Deadline		
▪ Must Resolve the matter with the Customer within 14 calendar days	N	No field to indicate target resolution date and actual resolution date.
▪ Must provide a timely report to OCS (DPS) identifying all cases that were completed and indicating whether the case was resolved to the customer's satisfaction	Y	There is a "Satisfied" field.
Customer Protections		
▪ Must afford the customer protections under 16 NYCRR Part 12.	Y	There is a PSC Code (PSCC)-hold field. This is a screen in CAS used to put a collections hold on accounts/complaints referred to PSEG LI by the DPS.
Other		
▪ Should keep complete record of each customer contact that is handled.	Y	There are customer contact fields for Email, Phone, Secondary Phone, and Address Information.
Report QRS Case Status to DPS to Indicate		
▪ QRS Cases Resolved and Closed	Y	Field exists to indicate Case Closed.
▪ QRS Cases Unresolved and Closed	N	No field to differentiate between Cases that are Resolved and those that are Unresolved.
▪ QRS Cases Resolved and Closed, Unresolved and Closed, Complete Resolution Pending Completion of Work (for cases that have been closed but full resolution will not take place until sometime in the future)	N	No fields to indicate that full resolution will not take place until future and a follow-up date.

Source: NYS DPS Office of Consumer Services QRS Guide April 2015 Ver.2.5, DR 93, March 13, 2018 email from PSEG LI.

- The CTS does not track data for DPS reporting:
  - CTS data does not allow distinction between "unresolved and closed" vs "resolved and closed". A data field exists to indicate "case date closed" but there is no data field to indicate whether the case is considered "resolved" or "unresolved".[75]

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[75] DR 93 Supplemental Attachment 01 – CTS All Data Report - Confidential

- The system does not allow for cases to be differentiated between those that are closed but will require future work for full resolution, and those that do not need to be followed up.[76]

- PSEG LI reports that cases are "closed" within the 14 days as this is the requirement.

- As currently used, the CTS database cannot be used for internal reporting to determine if customer contacts occur within the two (2) hour window for DPS collection and service related complaints. The CTS tracking system does not require the specific time of day the case was initiated or require the specific time the customer was contacted.

12. PSEG LI Customer Relations personnel do not always record all case data in CTS.

- As shown in **Exhibit XI-19**, PSEG LI does not input all required data in to the CTS database. "Date Closed" and "DPS Closed" are the only fields consistently used.

Exhibit XI-19
Results of NorthStar Review of CTS Database Records (1/1/2015 – 7/25/2017)

CTS Field	Number and Percent of Times that Field is Used					
	DPS Complaints		Other Complaints		Total Complaints	
	No.	Percent	No.	Percent	No.	Percent
Customer Contact Date Entered	53	2%	14	0%	67	1%
Customer Contact Time Entered	4	0%	1	0%	5	0%
Customer Email Entered	11	0%	1	0%	12	0%
Times Customer Phone Number Entered	902	39%	312	9%	1,214	20%
Customer Satisfied / Not Satisfied Entered *(~Resolved / Unresolved)*	34	1%	5	0%	39	1%
Date Closed	2,228	95%	3,248	91%	5,476	92%
DPS Closed	2,083	89%	NA	NA	NA	NA
Cases with "No" in DPS Closed field	26	1%	NA	NA	NA	NA
Breakdown of DPS Data Cases						
QRS	2,249	96%	NA	NA	NA	NA
SRS	88	4%	NA	NA	NA	NA
Total Case Records	**2,337**	**100%**	**3,588**	**100%**	**5,925**	**100%**

Source: DR 93 Supplemental Attachment 01, NorthStar Analysis.

- NorthStar examined sample PSEG LI – DPS Complaint case files and found that starting in 2015, DPS case referral emails sent within PSEG LI include embedded tables which state the Date, Type, Case Number, Customer Contact Required by, and Case Resolution Deadline. The entered Customer Contact Required by date time and Case Resolution date are a means to monitor customer complaint deadlines.[77]

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[76] DR93 Supplemental Attachment 01 – CTS All Data Report - Confidential

[77] DR 595 and596

13. NorthStar's review of QRS case files identified several process improvements made by PSEG LI.

- NorthStar's review revealed PSEG made several improvements to QRS case file process during the audit period, including the following:

  - Enhancements made to internal email to specify DPS case classification type, required deadline for contacting customer, and case resolution date.[78]
  - Creation of a DPS Complaint Response form for PSEG LI to communicate complaint resolution back to DPS.[79]
  - Inclusion of a case task checklist in internal email to track the following activities:[80]
    1) Contact Customer
    2) Open Case in CTS (make sure to notate Date & Time of Initial Contact)
    3) Notate Diary
    4) Place collections hold on account "PSCC" if applicable
    5) Complete Complaint Response Form
    6) Update DPS Portal
    7) Close in CTS
    8) Close in DPS Portal
    9) Create Case file

- NorthStar's review also noted more consistent documentation in CAS notes regarding the time of day customer contacts were initiated or completed; however, this data is still not always recorded.[81]

14. NorthStar's detailed review of QRS case files identified instances in which PSEG LI provided incorrect or insufficient information to customers or did not update the CAS system with information learned during customer interactions.

- NorthStar's review of QRS case files identified two instances in which CSRs provided incorrect information to customers in a QRS case follow-up.

  - PSEG LI manually calculated an incorrect credit amount –[82]
  - In response to a customer inquiry, PSEG LI communicated the wrong interest rate for billing overpayments[83]

- NorthStar identified instances in which CSRs resolved the DPS complaint but did not inform customers of assistance programs or did not update the CAS with relevant information.

  - *PSEG LI did not inform customers of assistance program* – During complaint responses to QRS and SRS, customers have indicated that they receive assistance from programs such as Home Energy Assistance Program (HEAP), Medicaid, Food

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[78] DR 596 Case 531254

[79] DR 596 Case 531860

[80] DR 770 Emails in Case files

[81] DR 596 Attachments 1 & 2

[82] DR 770 Case 719922 - Confidential

[83] DR 944

Stamps, and Supplemental Security Income (SSI) (prerequisites for customers to participate in the Household Assistance Rate Program); however, the customer is not consistently informed of the assistance program.[84]

  - *PSEG LI did not apply senior protections in CAS for elderly customers* – There are instances in which customers indicated they were elderly, but special senior protections were not applied in CAS.[85]

- NorthStar's case review also identified the following:

  - CAS notes do not consistently capture both the date and time customer communication occurred or notes of complaint discussion.[86]
  - Credit calculations are performed manually.[87]
  - CAS notes do not always match actual action performed for customer.[88]

15. **NorthStar's review of PSEG LI documentation indicates that case files did not consistently reflect that timely, accurate and quality responses occurred. This is partly attributed to incomplete case file documentation and ambiguity as to the time of day customer response occurred.**

- In May 2015, PSEG LI began to use a Form to document PSEG LI's actions to resolve the customer complaint and the DPS response date.

- NorthStar reviewed sample of case files. About half of the post-April 2015 case files included the DPS Complaint Response Form.[89]

- When included in the file, the DPS Complaint Response Forms showed that responses to DPS were timely, accurate and of sufficient quality. On average, the time between the Complaint Date and DPS Response Date was less than 3 days.[90]

- Copies of the DPS customer close out letter are not consistently included in case files.[91]

- PSEG LI's DPS Complaint Response Form does not contain necessary information regarding the times of day the complaint was filed and the customer was contacted. It is therefore unclear whether PSEG LI informs DPS whether it has contacted the customer within two hours, as required for a collection or service-related complaint.[92]

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[84] DR 93 Supplemental Attachment 1 (Cases 518692, 718257, 722818, 514380) – Confidential, ref to DR 980 Attachment 1

[85] DR 770 (Case 519521) and DR 93 Supplemental Attachment 1 & DR 980 Attach 1 (Cases 712820, 625702, 715931)

[86] DR 770 Test Cases (all except 519521)

[87] DR 770 Test Cases (719922)

[88] DR 770 Test Cases (719922) and DR 93 Resolution & Adjustment Rationale

[89] DR 595, DR 596, DR 770

[90] DR 595, DR 596, DR 770

[91] DR 596 Case 611843, DR 770 Case 613674

[92] Example of form in DR 596 DPS Case Number 611843

16. LIPA's role in customer complaint handling is limited to cases that have been appealed.

- As outlined in its tariff, LIPA does not become involved in the complaint process unless a customer requests an appeal of an informal hearing or review decision made by the DPS.

- **Exhibit XI-20** provides a summary of LIPA's DPS case log.

Exhibit XI-20
LIPA DPS Appeal Case Log (2014 -2017)

Year	Number of Appeals					
	Received	Open	Breakdown of Open Appeal by Type			
			Claim	285 Rate Issue Appeal	Shared Meter	Winter Bill Appeal
2014	36	0	0	0	0	0
2015	37	3	0	0	3	0
2016	11	3	0	0	3	0
2017	33	31	0	4	26	1
Total	**115**	**37**	**0**	**4**	**32**	**1**

Source: DR 98 supplemental, IR 63, Email received January 30th, 2018, NorthStar Analysis, DPS.

- As shown in **Exhibit XI-20** 37 of the 115 claims received between 2014 and 2017 remained open as of December 31, 2017. LIPA's response time is dependent upon the receipt of a recommendation from DPS.

- LIPA follows up with DPS on a monthly basis regarding appeal case recommendations.[93]

- LIPA receives a limited number of appeals in a year and has consistently adopted decisions made by the DPS.

Call Center and Customer Operations

17. Although CAS is an aging system, PSEG LI has successfully implemented a number of enhancements to ensure CAS and its other customer systems continue to meet the needs of users and the changing technology environment.

- CAS was installed in 1975 and serves as the system of record and manages the data for over 1 million customers.[94] Key CAS system interfaces include the following:[95]
  - EBO is used to handle summary billing, third party billing (electrics marketers) and allocation of payments. It prepares bill print line items for the paper bill and enables CSRs to view customer bills when inquired by a customer. CSRs use EBO online to view and update the customer account information through a Web browser tool or desktop application.
  - The Agent Desktop interface was added to provide a more user friendly interface for the call center, customer offices and collections. Agent Desktop pulls data from both CAS and EBO and allows users to sign-in to a single system.[96]

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[93] January 29th, 2018 follow-up, IR 63

[94] DR 196, direct observation of CAS system use by the contact center

[95] DR 196 and 577

  - Exception Memo Management System (EMMS) holds CAS transactions that are unposted due to errors during the daily billing run. The system works as a series of work queues so that error transactions can be sorted by different criteria and assigned to billing clerks for them to correct and re submit the failed transactions.
  - Outage Management System (OMS)
  - Non-outage work management/dispatch
  - Mobile dispatch
  - Meter reading and meter data management
  - Payment processing systems
  - The IVR system, text and email
  - My Account
  - Collections systems
  - SAP.

- Upon transition, PSEG LI upgraded the IVR to provide increased functionality and improve the customer experience. Enhancements included:[97]

  - Natural language, which allows a customer to speak to the IVR
  - Virtual hold, which allows the customers to be called back when they have reached their place in the queue, rather than continuing to hold
  - Proactive notifications
  - After call survey capability
  - Outage reporting[98]

- Other recent enhancements to CAS include:

  - New mainframe hardware and software.[99]
  - Debt Next, which allows PSEG LI to assign collection accounts to the various outside collection agencies based on agency performance, add layers of collections agencies, and improves collections performance monitoring.[100]
  - Improvements to the paperless billing process which allows customers to view their full bill from their email with an attached pdf. Customers can also make a payment directly from their email.[101]
  - Improvements which allow CSRs to control the phone system and provide them with information on a customer's choices within the IVR.[102]

- To address potential resource issues associated with the maintenance and support of the aging CAS system, PSEG LI retained the experienced National Grid personnel upon transition, retained existing contractor staff and added a new contractor.[103]

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[96] IR 94

[97] DR 975 Attachment 3

[98] IR 94

[99] DR 719 CONFIDENTIAL

[100] DR 196

[101] DR 196

[102] IR 94

[103] DR 719 CONFIDENTIAL

- PSEG LI's current strategy is to maintain CAS as its core customer system, while making improvements and investments in customer-facing systems and technologies that support achievement of OSA targets.[104] PSEG LI has no plan to replace CAS in the immediate future as the system continues to perform adequately.[105]

  - During the prior LIPA management audit in 2013, the PSEG LI/LIPA transition team performed a technical assessment of the CAS system, with the ultimate goal of replacing CAS with a modern Customer Information System within the next five years.[106]
  - In October 2016, PSEG LI performed an updated analysis of the CAS system and estimated that a replacement system would cost between $75 and $125 million. Current CAS operations and maintenance (O&M) costs run about $6 million per year.[107]
  - NorthStar found no significant issues with PSEG LI's analysis.

18. CAS and associated customer systems adequately support LIPA/PSEG LI's technical business needs and processes.

- According to PSEG LI, CAS has maintained 100 percent uptime/availability (other than planned maintenance outages) since January 2014.[108]

- NorthStar performed side-by-side with CSRs in the call center.[109] The CSRs were able to readily navigate CAS and the system did not appear to cause any delays in call handling.

- CAS and its supporting systems were able to support a number of recent rate changes:[110]

  - April 11, 2014 rate change and PILOT pricing change.
  - April 1, 2015 rate case tariff changes affecting all customer rate pricing.
  - 2016 rate case changes including new rate classes, removal of seasonal rates, and modifications due to revenue decoupling.
  - January 1, 2017 rate case change involving the addition of a new factor – Delivery Service Adjustment and changes for all rate codes.

- CAS was able to support other initiatives including bill redesign, modifications to budget billing, billing improvements related to the LI Choices and Green Choice programs, and the billing exception/error memo process. All of these changes were undertaken in 2016.[111]

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[104] DR 719 CONFIDENTIAL
[105] DR 719 CONFIDENTIAL
[106] Matter 12-00314, Comprehensive Management and Operations Audit of Long Island Power Authority Final Report by NorthStar Consulting Group dated September 23, 2013

[107] DR 719 CONFIDENTIAL
[108] DR 974, data through October 2017.
[109] IR 94
[110] DR 196
[111] DR 196

- CAS system interfaces allow customers to pay by credit card, debit card or check through the IVR.[112] Customers may also request payment arrangements and credit extensions, report service issues, enter a meter read and enroll in balanced billing. CAS is then updated accordingly.

- CAS maintains at least two years of CSR diary entries providing information on customer contact and notifications.[113]

- There are various controls built into CAS to ensure compliance with the special protection requirements of HEFPA.
  - Accounts of customers on life support/life sustaining equipment are specifically coded. The coding can only be added or removed by one group within PSEG LI. The coding is included in the files sent to field collection to prevent termination.[114]
  - Payment controls exist for accounts that are eligible for field termination to prevent inadvertent disconnection following same-day payment. If the customer tries to pay through the IVR, they are routed to a CSR, and the website payment capability is disabled.[115]
  - Coding is placed on a customer's account within CAS to prevent collections actions on disputed amounts associated with complaints filed with the DPS.[116]

19. As measured by average speed of answer and abandonment rate, PSEG LI's call center's performance is consistent with service level requirements.

- The A&R OSA targets and actual performance for ASA and abandonment rate are provided in **Exhibit XI-21**. PSEG LI achieved the maximum performance incentive in 2014, 2015 and 2016.

Exhibit XI-21
Call Center Performance – ASA and Abandonment Rate

Year	ASA (Seconds)				Abandonment Rate			
	Target (100% of Base Points)	Max Incentive (150% of Base Points)	Actual	Result	Target (100% of Base Points)	Max (150% of Base Points)	Actual	Result
Baseline	93				4.2%			
2014	79	70	54	Max	3.8%	3.5%	2.6%	Max
2015	66	48	35	Max	3.4%	2.9%	1.4%	Max
2016	53	26	24	Max	3.0%	2.2%	1.1%	Max

Source: DR 18 Attachments 1-3 and DR 25 Attachment 1.

  - ASA is measured as the total time on hold of all answered calls, plus the calls effectively concluded within the IVR (which are included as no wait time) each

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[112] DR 975 Attachment 1
[113] Direct observation of CAS, IRs144, 188 and 189
[114] IR 144
[115] IR 144
[116] DR 978

month divided by the total number of calls answered each month.[117] The baseline performance level is 93 seconds; target is 26 seconds by 2018.[118]
    - Abandonment rate is calculated as the percent of calls that hang up (abandon) after they are offered to the CSR queue. This statistic is calculated as the number of abandoned calls per month divided by the total offered calls per month including those handled by the IVR, expressed as a percentage.[119] The pre-2014 baseline performance level was 4.2 percent; the target is 2.2 percent by 2018.[120]

- Abandonment rate and ASA are commonly used utility call center metrics. Many utilities use a service level standard (e.g., 80 percent of calls in 60 seconds) instead of ASA. Increasingly utilities are weighing the relative value of aggressive call answer standards and are simultaneously trying to drive customers to lower cost options. First call resolution is also common industry metric. First call resolution was added as a Tier 2 metric in 2017. PSEG LI and LIPA have discussed the possibility of elevating it to Tier 1.[121]

- According to PSEG LI, the call center abandonment rate and ASA A&R OSA targets were set to achieve first quartile lower boundary level performance of American Gas Association (AGA) and Edison Electric Institute (EEI) peer groups by contract year five.[122] Due to confidentiality agreement requirements, NorthStar did not verify the peer group target.[123]

- At NorthStar's request, PSEG LI ran scenarios evaluating the cost savings associated with a reduction in service level targets. The reduction in the number of required CSRs was nominal.[124]

20. PSEG LI has extensive and effective processes for analyzing and reflecting feedback from customers.

- PSEG LI performs detailed analyses of JD Power survey results (residential and business) to identify opportunities for improvement and increased customer satisfaction.[125] PSEG LI developed a JD Power Interactive Dashboard that is used by Customer Intelligence and various other business units to evaluate customer perception and identify potential improvement opportunities.

    - Much of PSEG LI's outreach is targeted at improving its reputation and increasing its JD Power scores.
    - JD Power "verbatims" are also used to identify process improvement opportunities and PSEG LI may contact a customer to address specific customer issues.[126]

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[117] DR 25 Attachment 1
[118] DR 25 Attachment 1
[119] DR 25 Attachment 1
[120] DR 25 Attachment 1
[121] LIPA/PSEG LI Fact Verification
[122] DR 25 Attachment 1
[123] DR 23
[124] DR 101, 711, 712, 713
[125] Demo of the JD Power Interactive Dashboard (IR 122)
[126] IR 169, DR 109

  - In 2014, PSEG LI launched the Customer One program, designed to improve residential and business customer satisfaction, with the vision of achieving 1st quartile JD Power performance by 2018.[127] PSEG LI established six JD Power Project Teams aligned with the JD Power categories. The Customer One effort is discussed in further detail in **Chapter XIII – Performance Management**. The six JD Power categories are:
    - Power Quality & Reliability,
    - Price,
    - Billing & Payment,
    - Communications,
    - Corporate Citizenship, and
    - Customer Service.

- As discussed previously, residential and non-residential customers are asked to complete a brief, five to six question survey following contact with the call center. Customers are also asked to complete a survey upon contact with the Energy Efficiency and Renewable Energy Infoline.[128]

- Personal contact follow-up phone surveys are conducted with a sample of customers that have visited a customer office, had contact with a Major Account Representative or an Electric Field Representative (service interruption).[129]

- In addition to its routine surveys, PSEG LI also performs targeted research.

  - In late 2015, PSEG LI established a cross-functional team to increase customer satisfaction with vegetation management. The objective was to assess customer awareness and to identify customer pain points and improvement opportunities. As part of this effort, in April 2016, PSEG LI surveyed customers regarding its tree trimming practices and vegetation management contractor performance to assess customer understanding of and satisfaction with the program.[130]
  - Over the past few years, PSEG LI has obtained feedback from customers on the rebranding of the Customer Order Fulfillment Department, the Solar Program, key account customer perceptions, and My Account design.[131]

- The Customer Intelligence Team works with various departments to identify key business problems, determine availability of data, and propose intelligence-based solutions that enhance the customer experience. The team conducts primary and secondary research, identifies lessons learned and industry best practices, and analyzes data to prioritize customer centric program and process improvements.[132]

- PSEG LI and LIPA began conducting customer focus groups in 2016. The focus of several of the customer focus groups was on improving customer perception.[133] Topics

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[127] DR 312
[128] DR 109, Call center visit (IR 94)
[129] DR 109 Attachments 3 - 5
[130] DR 109 Attachments 6 and 7
[131] DR 109 Attachments 8-17
[132] DR 109, IR 169
[133] DR 579 Attachments

to date include: rates and property taxes; bill redesign; energy efficiency program logos and taglines; consideration of different rate plans (e.g., green, time-of-use); perceptions and reactions to specific topic areas from the JD Power survey for customers 55 years of age and older; effectiveness of potential advertising campaigns.[134]

21. PSEG LI's call center and collections quality assurance and customer service staff training processes and procedures comply with state laws and regulations.

- The call center quality assurance (QA) performance evaluation process includes the review of whether the CSR followed policies and procedures for customer verification.[135] For collections calls, PSEG LI follows a checklist that includes HEFPA regulations.[136]

- NorthStar reviewed PSEG LI's customer service procedures/job aids and training materials, summarized in **Exhibit XI-22**. The procedures address a number of requirements of 16 NYCRR Parts 11 and 13. NorthStar identified no violations of regulatory requirements.

Exhibit XI-22

Customer Service Staff Procedures/Job Aids and Training Materials Reviewed by NorthStar

Procedure Job Aid	Requirements Addressed
Customer Identification (ID) Verification	• Service may be denied to applicants who fail to provide reasonable proof of identity • CSR must send the customer a denial of service letter
Collection Analysis	• Payment amounts required • Agreements including $10 • Department of Social Service referrals • Income determination
Medical Emergencies	• A claim can be provided over phone and remain in effect for 5 business days • Collections activity will be suspended for 30 days • Coding for medical accounts
Financial Assistance Programs	• HEAP (emergency, regular, seniors) • Emergency Assistance • Residential Energy Affordability Partnership (REAP) • Project Warmth
Residential Applications and Deposits	• Information required • Written applications • Must be established within 5 days • Deposits • Other requirements of 16 NYCRR Part 11.3
Commercial Application and Deposits	• Application form • Deposits • Requirements • Special accounts (seasonal, religious, etc.) • Denial of service

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[134] IR 71 (attendance at the 6/27/17 Customer Focus Group), DR 578, DR 579 Attachments 1, 4, 8, 9, 12, DR 109 Attachment 19

[135] DR 580 Attachments 7-9 and DR 582

[136] DR 582 Attachment 8

Procedure Job Aid	Requirements Addressed
Collections	• Notification prior to disconnection • Dates and hours for disconnection • Internal weather restrictions • Two family and multiple family dwellings • Dormant review • Collections timeline • Payment agreements • Reconnection within 24 hours • Special protections • Late payment charges
Payment Arrangements	• Options available for customers who have been locked for non-payment

Source: NorthStar Analysis, DR 440, 441, 580 and associated attachments.

22. Other PSEG LI Departments provide the call center with information as required.

- Significant program or system modifications such the introduction of the new OMS or the change to the budget billing program are incorporated into the call center training.[137]
  - Trainers within the Customer Technology group provided the call center with training on the new OMS.
  - Modifications to the budget billing program were handled through a train the trainer effort. Trainers within Customer Technology developed the materials.
  - Other information might be provided to the supervisors who will provide the information to the CSRs.

- Various groups develop customer operations job aids for topics such as the Federal Emergency Management Agency (FEMA) storm hardening program, changes in tree trimming, stray voltage, rate changes and the changes in the communications process between the call center and collections dispatch.[138]

- Responses to frequently asked questions (FAQs) for significant capital projects or other utility programs that may affect the customer (e.g., vegetation management) are provided to the call center.

23. PSEG LI does not comply with the denial of service requirements of HEFPA regarding payment plans for amounts due and communicating with applicants that are verbally notified of the need to provide additional information.

- **Exhibit XI-23** summarizes the requirements of 16 NYCRR Part11.3 - Applications for residential service:

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[137] DR 440, IR 97

[138] DR 440 Attachments

Exhibit XI-23
16 NYCRR Part 11.3 Applications for Residential Service – Summary of Key Requirements

Section	General Requirement
11.3(a)(2)	PSEG LI must provide service to an applicant who owes the utility money from a previous service if: • The applicant make payment in full • Agrees to a payment plan • Has a pending billing dispute and has paid other required amounts • Is the recipient of Public Assistance
11.3(a)(4)(v)	An oral application for service shall be deemed completed when an applicant who meets the requirements of paragraphs (1)-(3) of this subdivision provides his or her name, address, telephone number and address of prior account (if any) or prior account number (if any). A distribution utility may establish non-discriminatory procedures to require an applicant to provide reasonable proof of the applicant's identity. Service may be denied to applicants who fail to provide reasonable proof of identity. A distribution utility may require an applicant to complete a written application if: (a) there are arrears at the premises to be served and service was terminated, disconnected or suspended for nonpayment or is subject to a final notice of termination, disconnection or suspension; (b) there is evidence of meter tampering or theft of service; (c) the meter has advanced and there is no customer of record; or (d) the application is made by a third party on behalf of the person(s) who would receive service
11.3(b)(1)	Denial of application for service--notice. (1) As used in this subdivision, the terms deny and denial shall mean any determination in response to an application for service, that service will not be initiated as requested. An application for service not approved within three business days shall be deemed denied.
11.3(b)(2)	No distribution utility shall deny an application for service without sending to the applicant, within three business days of receipt of the application for service, written notice which: (i) states the reasons for the denial; (ii) specifies precisely what the applicant must do to qualify for service; and (iii) advises the applicant of the right to an investigation and review of the denial by the commission or its authorized designees if the applicant considers the denial to be without justification. The distribution utility shall advise the applicant of the appropriate address and telephone number of the DPS, including the DPS hot-line number and the times of its availability.
11.3(b)(3)	The notice required by paragraph (2) of this subdivision shall be in writing and shall be either served personally or mailed to the applicant. When the written notice is given by mail, the distribution utility shall make a reasonable effort to provide immediate notice orally.
11.3(b)(4)	Every distribution utility shall maintain, for a period not less than one year, records of oral or written requests for service that are denied, including the name and address of the applicant, the date of the application and the utility representative(s) who denied it.

Source: 16 NYCRR.

- PSEG LI's definition of "denial of service" may not be technically consistent with the requirements of HEFPA. PSEG LI does not consider it to be a "denial of service" if the applicant is told that he/she must go to the office and provide additional information, as the customer has not yet technically made an application. As a result, these customers are not sent the letters required by HEFPA Section 11.3(b)(2), shown in **Exhibit XI-23**.[139]

- PSEG LI does not consistently offer payment plans to applicants owing money in the Denial of Service Letters as a specific action to receive service or offer a payment plan as an option to remediate money owed PSEG LI.

    - Typical language in PSEG LI's denial of service letter includes: "Your application for electric service at the above address is being denied for the following reason: due to your prior charge off account. Due to the status of your previous account at: {address}, Account {number}. Service will be established at the aforementioned address once the balance has been paid in full {dollar amount}."[140]
    - Section 11.10 of HEFPA requires a written offer of a payment agreement when payment of outstanding charges is a requirement for acceptance of an application for service.
    - In a review of Denial of Service letters, NorthStar found, in practice, payment plans are offered if the service was terminated in less than the previous 60 days, otherwise full balance is required.[141]

- At NorthStar's request, PSEG LI provided case histories and denial of service letters for a sample of escalated customer complaints coded as "Denial of Service [142] NorthStar's review found that, when the letters were sent, they addressed the requirements listed in **Exhibit XI-24.**

Exhibit XI-24
Results of NorthStar's Review of Denial of Service Letters and HEFPA Requirements

Requirement	Results
When sent, letters are sent within the required three days	NorthStar tested a sample of denial of service letters. PSEG LI, in the side-by-side testing, accessed the customer records from CAS and was able to provide the date of application.
Letters are specific as to the reason for denial and what must be done to receive service	Examples include: "Your application for electric service at the above address is being denied for the following reason: Please provide: ▪ A completed residential application ▪ Your Social Security Number ▪ A copy of a valid lease or deed to the property. ▪ A valid photo ID" "Your application for electric service at the above address is being denied for the following reason: due to your prior charge off account. Due to the status of your previous account at: {address}, Account {number}. Service will be established at the aforementioned address once the balance has been paid in full {dollar amount}."

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[139] IR 94

[140] DR 809

[141] IR 145, DR 576

[142] DR 93 and 806

Requirement	Results
Letters inform the applicant of his/her right to an investigation	Typical language includes: "If you are not satisfied with this response, you have the right to an investigation and review by the NYS Department of Public Service. You may contact the NYS Department of Public Service by calling 1 (800) 342-3377, between 8:30 a.m. and 4:00 p.m., weekdays, or in writing to 90 Church St, 4th Floor, New York, NY 10007-2919."[143] NorthStar verified the validity of the telephone number.

Source: DR 809.

24. PSEG LI complies with the same day payment processing requirements for accounts eligible for termination of 16 NYCRR Parts 11 and 13 as it relates to payments made directly to the utility, but does not have real-time information on payments made to authorized payment locations.[144]

- §11.4(a)(5) of HEFPA requires that: (i) No utility shall terminate or disconnect service for nonpayment of bills rendered, unless verified payment has not been made by the end of the notice period or been posted to the customer's account on the morning service may be disconnected.

- §11.4(6) of HEFPA requires that every utility take reasonable steps to ensure payments made in response to final notices of termination or disconnection: (i) are posted to the customer's account on the day payment is received; or (ii) are processed in some manner so that termination or disconnection will not occur. §13.3(d) provides similar requirements for non-residential customers.

- Prior to scheduling service disconnections for non-payment, Field Collections reviews all accounts eligible for disconnection for activity the prior day (e.g., phone call, payment, or DSS commitment to provide assistance), to ensure no payments have been made and to identify accounts with special collections codes.[145]

- Controls within the IVR and My Account require customers that are eligible for disconnection to make payments directly with a CSR.[146]

- The CAS posting of payments made to third-party payment locations (such as Western Union) is dependent on the timeliness of the third party's internal processes and business day rules. In general payments made to the third-party vendor during normal business hours will post to CAS the following business day. Payments made after business hours will post two days later.[147]

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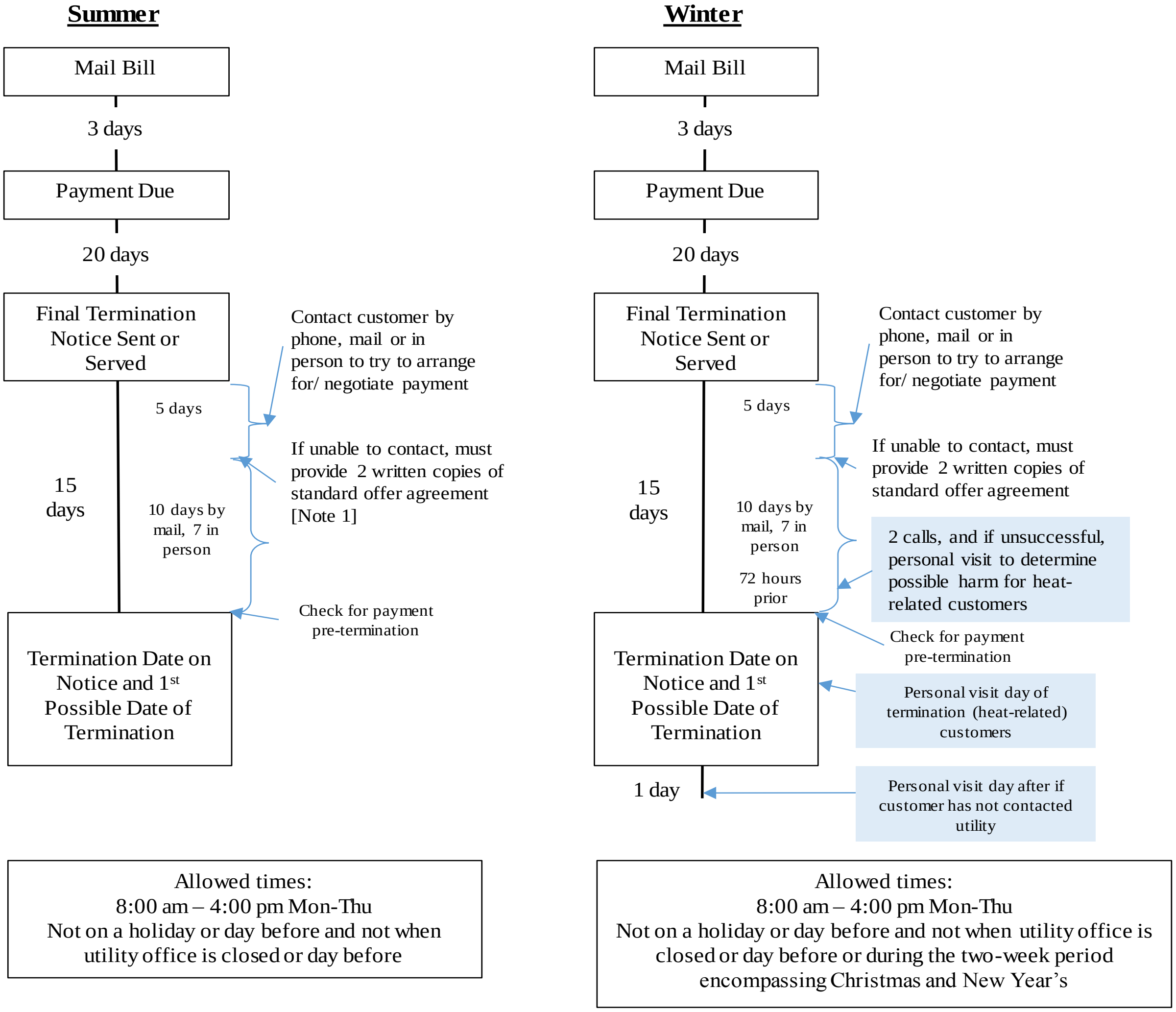
[143] DR 809
[144] DR 720
[145] IR 144
[146] IR 144
[147] IR 144, DR 979

- According to PSEG LI, if a customer is at the premises during a field collection visit and claims payment was made at a third-party vendor that has not yet posted payment, proof of payment may be requested and the service will be left on.[148]

25. PSEG LI's collections timeline is consistent with the requirements of 16 NYCRR Parts 11 and 13.

- **Exhibit IX-25** shows the required summer and winter collections timelines for New York residential customers that are not eligible for special protection. (As discussed in the Background section of this chapter, special protections are provided to certain classes of residential customers.)

Exhibit XI-25
HEFPA Residential Timeline – No Special Conditions [Note]



Note: Identified time durations represent the minimum amount of time between events.
Note: The utility may postpone a termination for 10 days for the purpose of negotiating payment terms (all seasons). The customer must be clearly advised of the postponement. If a postponement is made, the standard offer can be mailed 10 days before that date.
Source: Part 11 of 16 NYCRR.

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[148] DR 979

- Non-residential customers are not subject to the same protections and the utilities have greater latitude to terminate non-residential customers. In accordance with 16 NYCRR, residential customers are eligible for possible termination 45 days after payment was due (on the 46th day). Non-residential customers may be terminated between 25 and 28 days after payment was due.

- PSEG LI's collections timeline is consistent with the requirements of 16 NYCRR. **Exhibit XI-26** provides PSEG LI's residential customer collections timeline during winter and non-winter season.

Exhibit XI-26
Collections Timeline – PSEG LI Customers

Activity	Non-Winter	Winter
	PSEG LI (on or about)	PSEG LI (on or about)
First Bill Print and Mail	Day 0	Day 0
Due Date	Day 27	Day 27
Payment Delinquent	Day 27	Day 27
Reminder Notice	Day 30 on next bill	Day 30 on next bill
Reminder Call	Day 38	Day 38
Second Reminder Call	Day 45	Day 45
Third Reminder Call	Day 52	Day 52
Fourth Reminder Call	Day 58	Day 58
Second Reminder Notice	Day 60 on next bill	Day 60 on next bill
Fifth Reminder Call	Day 63	Day 63
Standard Offer Letter Mailed (Customer has 72 hours (3 days) to respond)	Day 65	Day 65
Phone Call informing customer that Standard Offer has expired	Day 70	Day 70
Second Phone Call		Day 73
Eligible for Field Collections/Termination	Day 75	Day 75

Bill notices or mailings are highlighted in grey.
Source: DR 108 Attachment 1, LIPA/PSEG LI Fact Verification.

- Numerous reminder calls are made during the non-winter season; these are above and beyond the requirements of HEFPA.[149] Two calls are required during the winter season; PSEG LI complies with this requirement, and makes additional calls.[150]

- NorthStar's review of collection files confirmed these various activities, consistent with the collections timeline.[151]

26. PSEG LI complies with the termination for non-payment notification requirements.

- **Exhibit XI-27** summarizes the New York termination for non-payment notification requirements.

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[149] DR 108 Attachment 1, DR 803 Attachments (documentation of call campaigns)
[150] DR 108 Attachment 1, DR 803 Attachments (documentation of call campaigns)
[151] DR 601, 602, 603, 766, 767, 768, IR 189

Exhibit XI-27
Termination of Service Requirements

Category	Requirement?		Controls/ Testing Results
	Residential	Non-Residential	
Notice Timing	**§11.4(a)(1)(v)**	**§13.3(c)(1)**	
Final termination notice must be sent (personally served or mailed) no less than 15 days before the date on the notice	✓		Termination date at least 15 days from notice date
A utility shall not terminate service (i) for five calendar days after a final notice of termination has been personally served upon the customer; or (ii) for eight calendar days after a final notice of termination has been mailed to the customer.		✓	Termination date at 8 days from notice date
Notice Language	**§11.4(a)(2)(i-v)**	**13.3(b)(1)(i-vi)**	
Notice must clearly state: Earliest date on which termination may occur	✓	✓	Clearly stated on bill
Reason for the termination, including total amount to be paid and the manner in which termination may be avoided	✓	✓	Reason and amount clearly stated on bill
Address and phone number of utility office to contact	✓	✓	Phone number and P.O. Box for mailing
Availability of utility procedures for handling complaints	✓	✓	Included
A summary of protections available	✓		Included as separate insert
Notice must have the following language printed on its face in size type capable of attracting immediate attention: THIS IS A FINAL TERMINATION NOTICE. PLEASE REFER TO THIS NOTICE WHEN PAYING THIS BILL or THIS IS A FINAL DISCONNECTION NOTICE. PLEASE REFER TO THIS NOTICE WHEN PAYING THIS BILL,	✓	✓ But does not specify exact language	Notices state: "THIS IS A FINAL TERMINATION NOTICE. PLEASE BRING THIS NOTICE TO OUR ATTENTION WHEN PAYING THIS BILL"
Not without verification that, through the end of the notice period: Payment had not been received at any utility office Payment had not been received at any office of any authorized collection agent			See Conclusion 24 for discussion of authorized collection agents

Source: IR 170, 88 and 189 (DR 766-768).

- A "Summary of Rights on Final Termination Notices" included with Final Notice Bills summarizes a residential customer's rights and protections under HEFPA. The summary includes the following:[152]
  - Notification that the customer should call the utility or visit an office if the customer has a dispute or to make payment arrangements.
  - Provides the phone number to call and the Post Office Box of the utility.

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[152] Summary of Rights on Final Termination Notices, DR 766

  - Provides the phone numbers for the DSS offices in Nassau County, Suffolk County and Queens.
  - Provides the phone number and address of the DPS.
  - Information on the availability of payment plans.
  - Special protections
  - Financial assistance and the DPS emergency hotline
  - Shutoff times and restoration charges.

- Field collectors leave green notices indicating whether service has been turned off or not and the amount the customer must pay to avoid disconnection or have the service reconnected. Notices are in English and Spanish.[153]

27. NorthStar found PSEG LI to be in compliance with other key requirements of 16 NYCRR Parts 11 and 13.

- Although allowed under HEFPA, PSEG LI does not generally require deposits from residential customers.[154]

- Field collectors attempt to contact customers prior to disconnection and offer customers a variety of payment options. Customers can make payments to the field collector.

- NorthStar observed field collections on September 28, 2017. No violations of 16 NYCRR Parts 11 and 13 were observed: the collector attempted to reach the customer; if no one was home the service was disconnected and a notice was left; and, receipts were provided for payments that were accepted in the field. Collections attempted to work with the customer to maintain service.[155]

- Customers on life sustaining equipment are coded as a critical facility (Code 13) within CAS. Only one group within Customer Operations can add or remove the LSE code. The code is included in the file of potential field terminations.[156] PSEG LI maintains the separate file of customers on life support systems as required by HEFPA.[157] As of December 21, 2017, 6,288 customers were on the list.[158]

- The meters of customers on life sustaining equipment receive a special seal. Only Customer Relations can request the installation or removal of this seal. The work order is initiated by Customer Relations; a Special Investigations Clerk generates a field order; and the seal is placed on the meter by the assigned Investigator. The investigator completed the job within the CGI work tracking system and notes in CAS that the action was completed.[159]

- HEFPA allows the utility to require quarterly recertification of financial need from LSE customers. PSEG LI does not require LSE customers to recertify financial need.

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[153] IR 188 and 189 (DR 766-768)
[154] Deposit may be required if the customer has previously filed for bankruptcy (IR 171)
[155] Collections field review (IR 189)
[156] IR 144, DR 994
[157] DR 994 Attachment 1 CONFIDENTIAL
[158] DR 994 Attachment 1 CONFIDENTIAL
[159] DR 993

- Entering the winter season, utilities must conduct a review of all heat-related residential customer accounts that do not have service to determine if the resident is likely to suffer a serious impairment to health or safety from a continued lack of service (16 NYCRR Part 11.5(c)(4)). NorthStar observed this review process, and found no violations of the requirements.[160]

  - One residence was vacant with a "for sale sign" – service remained off.
  - Another was vacant, boarded up with an overgrown yard – service remained off.
  - One residence was vacant, but there were boxes in back covering an open door. The collector attempted to contact the neighbor but they were not home – a referral was sent to DSS.
  - Another was vacant and had a Notice of Public Hearing on the door – service remained off.

D. RECOMMENDATIONS

1. At the time of the next bill redesign, revise bill formats to include missing information required by 16 NYCRR Parts 11 and 13 (e.g., definition of kW, late payment date line and an explanation as to how the bill can be paid).

2. Issue denial of service notices as required by 16 NYCRR Parts 11 and 13. Offer payment arrangements as required by Part 11.

3. Revise the processes used by PSEG LI to respond to complaints received by the DPS as follows:

   - Create a case file checklist to include in case files to ensure documentation is complete.
   - Develop an integrated program management approach to ensure customers are provided information on all programs available to them. One approach would be to create customer profile worksheet with cross reference to applicable programs and/or relevant protections.
   - Eliminate practice of hand calculations and implement use of excel template calculators. Modify the "DPS Complaint Response Form" to include:

     - Time and date customer complaint was created
     - Applicable customer contact timeline (e.g. 2-hour, next day etc.)
     - Time and date customer was contacted
     - Any special protections or customer assistance programs the customer was referred to
     - Date form submitted to DPS.

   - Implement a process to ensure PSEG LI includes copies of the DPS customer close out letters in the case files.

4. Modify the CTS system to improve DPS complaint tracking and reporting ability. Add data fields including:

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[160] IR 189

- The original source of complaints referred by DPS (i.e., direct from customer, Consultant, Government Official/Executive Correspondence).
- Customer contact deadline.
- Closeout deadline.
- Resolution status field to differentiate between cases that are “Resolved and Closed” vs “Unresolved and Closed”
- Indication the case is “Pending completion of future work” to allow for active follow-up.
- Modify the Date Opened field to allow for capturing of time of day a case is created.
- Modify Date Contacted field (default time of day set at 0:00) to force user to adjust time. Adjust internal processes to ensure data entry into this field.

5. Implement a Quality Assurance Program in Customer Relations. Recommended items for review include:

   - Data is entered in CTS
   - CAS diary entry includes the time customer contact occurred
   - Case files are completed
   - Appropriate tools and methodology are being used to calculate adjustments
   - Consistent treatment of customers with similar issues
   - Customers complaint concerns appropriately addressed
   - DPS Complaint Response Form is used to track response to DPS cases.

XII. EXTERNAL OUTREACH AND COMMUNICATIONS

This chapter provides the results of NorthStar's review of LIPA's and PSEG LI's outreach and communication programs.

A. BACKGROUND

In accordance with the Amended and Restated Operating Service Agreement (A&R OSA), outreach and customer communications are primarily PSEG LI's responsibility. PSEG LI serves as the face of the utility with the customer, the public and the media. LIPA may appear before the public or other stakeholders on matters of policy (e.g., Reforming the Energy Vision (REV) or the Integrated Resource Plan (IRP)) or changes in taxes, finance and bond restructuring. LIPA's primary interface is with the Board of Trustees (BOT).[1] LIPA's strategy centers on strengthening its long-term reputation as a not-for-profit utility enabling clean, reliable and affordable power.[2] **Exhibit XII-1** provides a list of stakeholders and typical LIPA communications. Information is also publicly available on LIPA's website.

Exhibit XII-1
LIPA Communications

Stakeholder	Types of Communications
Investors	• Email alerts on important energy policy decisions. • Distribution of interim financial statements and budgets. • Attendance at a minimum of 2-3 investor forums per year.
BOT	• BOT materials, emails and phone communications.
Government Officials	• Annual visits to state, Federal and local officials to discuss energy policy and utility matters. • More frequent communications as needed or on topics of interest or regional issues. • Receive annual reports and budget reports.
Media	• As needed regarding important policy decisions.
Other Stakeholders	• LIPA and PSEG LI recently established a Community Advisory Board (CAB) consisting of not-for-profit, labor, business, education, and senior communities to solicit feedback on utility policies and programs. • Public comment meetings before the annual budget, major tariff changes, or other significant items. • Public may appear and comment at BOT meetings.

Source: DR 39.

A number of PSEG LI organizations provide communications and outreach services:

- PSEG LI's External Affairs organization serves as the primary interface with local officials. This function reports to the Public Service Enterprise Group (PSEG) VP of State and Government Affairs.[3] In addition to proactive communications, External Affairs is also responsible for outreach related to specific capital projects. Capital project outreach is charged to the respective capital projects and not to External Affairs' general

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[1] IR 167

[2] DR 39

[3] Orientation Presentation

budget.[4] District Managers (DMs) manage relations with elected/public officials; provide outreach support for the vegetation management program; and perform outreach for major capital projects, including Federal Emergency Management Agency (FEMA) work.[5] For most of the audit period, four DMs served the LIPA territory.[6]

- Central Nassau – North Hempstead (about 30 villages) and Oyster Bay (18 villages, the cities of Glen Cove and Hempstead, and unincorporated hamlets)
- Queens/Nassau – Hempstead and the Rockaways
- Western Suffolk – Huntington, Smithtown, Babylon and Islip
- Eastern Suffolk – Brookhaven, Riverhead, Southold, Southampton, East Hampton and Shelter Island.

- The PSEG LI Communications organization serves as the chief spokesperson for PSEG LI with the media. The organization manages internal and external communications, PSEG LI's social media presence, its website and intranet site. It also reviews customer communications produced by Transmission and Distributions (T&D) Operations and Customer Operations for brand compliance.[7] This function reports to the PSEG VP of Communications.[8]

- PSEG LI T&D Operations and Customer Operations perform the majority of the customer-specific outreach and communications. T&D Operations provides outreach support for vegetation management and construction projects. The Customer Experience & Utility Marketing Group within Customer Operations handles all communications with customers except social media. Social media is handled by the Contact Center.[9]

Exhibit XII-2 provides PSEG LI's budget and actual communication and marketing spending.

Exhibit XII-2
Communication and Marketing Budget and Actual Expenditures - 2015-2016

	Corporate Communications	Utility Marketing	External Affairs
2015			
Plan	$ 1,309,585	$ 5,659,747	$ 1,166,132
Actual	882,023	5,512,235	757,792
Variance	**427,562**	**147,512**	**408,340**
Explanation of Variance	Storm Response Contingency		Vacant position part of year; greater than planned capital project outreach so more time charged to the specific capital projects rather than the External Affairs budget

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[4] IR 68
[5] IR 190, DR 322
[6] In late 2017, the Central Nassau District was temporarily split in two districts while a new DM was being trained. The District was consolidated again in February 2018.
[7] IR 67
[8] Orientation Presentation
[9] IR 61

	Corporate Communications	**Utility Marketing**	**External Affairs**
2016			
Plan	$1,490,946	$6,744,915	$1,236,595
Actual	1,242,368	12,614,968	1,056,836
Variance	**248,578**	**(5,870,053)**	**179,759**
Explanation of Variance	Storm Response Contingency	Planned variance (TV ads) to increase customer satisfaction	Vacant position part of year; greater than planned capital project outreach so more time charged to the specific capital projects rather than the External Affairs budget

Source: DRs 320, 798, and 799.

B. EVALUATIVE CRITERIA

- Are incoming and outgoing customer communications effective and does PSEG LI make effective use of advanced technology?
- Has PSEG LI's outreach program been successful as it relates to key projects?
  - Does PSEG LI have an outreach program that effectively updates key stakeholders, elected officials, municipalities and customers on sensitive and/or potentially confidential critical infrastructure projects?
  - Are PSEG LI's capital project outreach budgets used for their intended purpose?
- Are the LIPA and PSEG LI organizations appropriately aware of applicable external affairs issues and outreach efforts?
- Are communication efforts with respect to the following program/stakeholders effective: tree trimming/tree advocates?
- Are communication efforts with respect to the following program/stakeholders effective: low income programs/customers?
- Is PSEG LI's website user-friendly, well-organized and does it provide customers and stakeholder with the necessary functionality?
- Does PSEG LI train its employees such that they may enhance and improve outreach?
- Does PSEG LI effectively plan, organize and execute its outreach programs and activities?

C. FINDINGS AND CONCLUSIONS

1. **PSEG LI uses a variety of mechanisms to communicate with its customers, ranging from door hangers to social media. Survey results (JD Powers and advertising agency surveys) indicate that its advertising and communication efforts are becoming more effective.**

- With the transition from National Grid to PSEG LI, the focus of customer communications shifted from promoting internal programs (e.g., My Account, budget billing) to increasing customer education and awareness.[10]

- PSEG LI communicates with customers through a variety of channels including bill inserts, bill messaging, advertorials, information in trade publications, social media, web

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[10] IR 143

banners, radio, television, direct mail, PSEG LI's website, emails, door hangers, billboards and representation at community events.[11]

- Customer communications address a variety of topics including billing and payment-related programs and services, policy changes (e.g., vegetation management) and rate cases, PSEG LI's efforts to improve reliability, energy efficiency and financial assistance programs.[12]
- The primary channel for inbound communication is the call center, which is discussed in **Chapter XI - Customer Operations**.
- PSEG LI also uses Facebook, Twitter, YouTube, and its blog "Plugged In" to communicate information and respond to customers.[13] PSEG LI's Social Media group responds to social media posts within 15 minutes.
- **Exhibit XII-3** presents PSEG LI's communication channels and their frequency in 2017.

Exhibit XII-3
Customer Communications Calendar – 2017

Channel	Examples	2017 Frequency
Direct Mail	My Account, Community Partnership Program (CPP)-March of Dimes, It's About You, Energy Efficiency (EE)	4 x during year
Email (about 450k subscribers)	My Account, EE analyzer and various programs, storms, safety (personal and public), paperless billing, direct pay, reliability, scam awareness, events, know your bill, financial assistance, storm updates	Multiple per month 1.5 average per week
Bill Inserts/Envelope [Note 1]	Customer rates, rate/bill changes, customer assistance, utility programs, energy efficiency, storm prep, savings tips, residential and commercial customer rights and responsibilities, assistance programs (financial assistance and Project Warmth)	Six x per year
Mass Media (TV, Radio, Print)	Energy efficiency, reliability, business testimonials, geothermal	Generally monthly but varies by channel
Advertorials	Reliability improvements, energy efficiency, outage reporting, rates and rate stability, storm hardening, bill redesign, emergency preparedness	Approx. monthly
Events	Energy efficiency giveaways	Proposed for latter half of 2017
Road Signs	Reliability investments and tree trimming	Second half of 2017
Social Media	Extensive – similar to emails and bill inserts, community events, regional projects, utility work and traffic closure	Multiple per month
Digital	My Alerts, My Account, storm alerts, EE analyzer and programs, business testimonial, geothermal	Monthly
Website	Utility programs, tree giveaway, EE analyzer, Nissan Leaf rebate	Variable
Billboards (LIRR/Bus)	My Alerts, My Account, storm prep, EE analyzer, savings, reliability	Rotate quarterly
Press releases	Programs, reliability projects – including general location and duration, power supply charge rates, storm preparedness, awards, energy savings tips, safety	As required

Note 1: The bill redesign was advertised on the bill envelope in addition to bill inserts.
Source: DR 39 and Attachments, 804 Attachment 22 and 23, DR 896.

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[11] IR 143, DR 804
[12] IR 143
[13] Review of Facebook and Twitter, DR 39, DR 111, DR 941 Attachment 1

- NorthStar reviewed the customer communications timeline and associated communications, and found them to be typical for a utility, seasonally appropriate, and covering an appropriate array of topics.[14]

- PSEG LI relies on JD Power survey results and surveys conducted by its advertising firms to assess its communications performance. Historically, PSEG LI has been in the bottom of the fourth quartile of comparable utilities in the JD Power Communications category. PSEG LI implemented some of the best practices from one of the JD Power top performers, by implementing more frequent communications and bolder, more attention-getting language.[15] In the second half of 2016, PSEG LI expanded its reach to customers using new TV ads, direct mail focused on community support, and increased run times of radio, print, TV and digital ads.[16]

- During the last few surveys, PSEG LI moved into the third quartile for the Communications portion of the JD Power Residential survey.[17]

  - PSEG LI was in the 4th Quartile in the July/August 2016 survey (referred to as 2017 Wave 1).
  - PSEG LI moved to the bottom of the 3rd Quartile in the 2017 Wave 2 survey (October/November 2016).
  - PSEG LI moved up slightly within the 3rd Quartile with the Wave 3 survey (January/February 2017) and maintained its position in Wave 4 (April/May 2017).
  - With Wave 1 of 2018, PSEG LI moved to the top of the 3rd Quartile and above the East Large average.

- PSEG LI commissions detailed surveys on the effectiveness of its major advertising campaigns.[18] The surveys provide information on customer perception, campaign awareness, marketing effectiveness (ads and channels), and reaction to specific ads and campaigns. They also identify opportunities for improvement.

  - In November 2013, PSEG LI commissioned a baseline study of residential customer awareness of PSEG LI. This study found that awareness of the change from National Grid to PSEG LI was fairly low, few customers were familiar with PSEG LI and perceptions were very shallow.[19] This and subsequent surveys were used to assess effectiveness and direct PSEG LI's marketing efforts.
  - A study conducted in June 2014 found that familiarity with the PSEG LI brand had increased, but opinions were not yet strongly developed. A limited number of customers recalled seeing PSEG LI's specific ads and were not strongly impacted by the advertisements. The survey also pointed to a lack of awareness of PSEG LI's energy efficiency programs.[20]
  - An October 2015 survey continued to show an increase in familiarity with the PSEG LI brand (a 72 percent increase from the first survey). PSEG LI achieved parity with

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[14] DR 804 Attachment 22 and 23
[15] DR 765
[16] DR 765
[17] IR 143, DR 765, DR 934 Attachment 2
[18] IR 143, DR 804 Attachments
[19] DR 804 Attachment 1
[20] DR 804 Attachment 3

other utilities and had significant brand strength around reliability and storm response. The public continued to recall seeing ads but had a low detailed awareness of programs and services.[21]

  - In March 2016, PSEG LI switched advertising agencies, resulting in a new baseline study. Overall, customers rated PSEG LI average to slightly above average with respect to their attitudes about PSEG LI features and benefits. Many respondents were not aware of the Home Energy Analyzer or any of PSEG LI's infrastructure improvements.[22] PSEG LI increased its marketing efforts in both areas. The advertising agency conducts subsequent surveys after each advertising campaign.[23]

2. **PSEG LI has not formally measured the success of its more proactive approach to external affairs and media relations; however, improvements are evident.**

- External Affairs DMs spend a significant portion of their time in the field working with constituents and building relationships. They are expected to respond to inquiries, complaints and concerns immediately.[24]

- Communications provides proactive media coverage (e.g., volunteerism, Federal Emergency Management Agency (FEMA) resiliency, My Account) and responds to media inquiries. The media is proactively notified of significant projects.[25]

- Media coverage appears to be more balanced, than at the time of NorthStar's prior audit (2013).

- PSEG LI reports positive feedback from improvements in storm communications made following Sandy.[26]

- PSEG LI reviews media clips on a daily basis and reviews the attendance at, and comments made during public meetings.[27]

- DMs report that constituents are pleased with the responsiveness of PSEG LI and the more proactive outreach efforts. They also report that the municipalities are beginning to see the effects of tree trimming on reliability.[28]

3. **PSEG LI has an effective vegetation management communication program.**

- PSEG LI launched an Enhanced Vegetation Management Program in 2014. Key components of the program were:[29]

  - A multi-year funding strategy to bring the distribution system to a four-year cycle.
  - Significant expansion of line clearances.

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[21] DR 804 Attachment 5
[22] DR 804 Attachment 13
[23] DR 804 Attachments 15-21
[24] IRs 68, 190, 191, 203, 204, 205
[25] IR 67
[26] DR 709
[27] LIPA/PSEG LI Fact Verification
[28] DR 709 Response and Attachment 2, various interviews
[29] DR 120

  - Use of an asset management-based model for circuit trim selection.
  - Enhanced customer outreach.

- PSEG LI's External Affairs organization provides annual briefings to elected and appointed governmental officials. The modified tree trimming program is discussed at these briefings.[30] External Affairs reports that the municipalities are beginning to see the relationship between tree trimming and increased reliability. PSEG LI may also meet with elected officials in towns and villages before tree trimming begins.

- Most of the tree trimming work is performed by contractors. Contractor specifications require that contractors "maintain field and supervisory personnel who will address questions and complaints from neighboring residents in a clear, prompt, professional and courteous manner." The specifications contain a number of other requirements regarding customer sensitivity.[31] Contractor performance is evaluated based on quality, customer service, leadership and communication (including customer communication).[32] Contractors are also evaluated based on post-distribution circuit trim customer survey results. Through August 2017, the satisfaction scores for individual contractors ranged from 69 to 71 percent.[33] NorthStar does not have details for the contractor numbers but the scores may be consistent with the overall survey results provided in **Exhibit XII-4**, later in this conclusion. Contractors have PSEG LI contact cards to give to customers that have questions.

- All contractors are provided with training before they perform tree trimming for PSEG LI. The training addresses customer concerns, customer service and communication tips.[34]

- PSEG LI's website includes pages devoted to its tree trimming program. Available information includes: clearances, debris removal, tree trimming contractors, hazard identification and reporting, frequently asked questions (FAQs) and the effect on reliability.[35] Customers are also able to request a vegetation management presentation for their community through the Community Partnership Program.

- PSEG LI sends letters and emails to customers two to three weeks before tree trimming begins in their neighborhoods, letting them know when work is scheduled. The notification includes the tree trimming supervisor's name and phone number, the Vegetation Management Manager's name and the PSEG LI Customer number. A door hanger is also placed on each customer's door, typically, two to three days before work starts.[36]

- Road signs promote the connection between tree trimming and fewer outages.[37]

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[30] DR 750 Attachment 9
[31] DR 401 Attachment 2
[32] DR 402 Attachment 1
[33] DR 836 Attachments 1-6
[34] DR 705 Attachment 5
[35] https://www.psegliny.com/page.cfm/Home/Safety/TreeTrimming
[36] DR 705 and Attachments, https://www.psegliny.com/page.cfm/Home/Safety/TreeTrimming
[37] DR 705 Attachment 4

- Tree trimming-related escalated complaints have decreased from 16 per thousand miles trimmed in 2014, to nine in 2015 and eight in 2016.[38] Through June 2017, the number had dropped to one escalated compliant per thousand miles trimmed.[39]

- Customer survey results indicate that while customers are generally satisfied with the tree trimming work, most do not recall receiving a notification.[40] Overall satisfaction increased from 65.5 percent in 2016 to 70.6 percent in 2017. Notification recall improved only slightly – 35.8 percent to 36.3 percent. **Exhibit XII-4** provides a comparison of customer satisfaction between 2016 and 2017. This information is not contractor-specific.

Exhibit XII-4
Vegetation Management Survey Results

Metric/Question	2016 (Survey Response Date)	2017 (Survey Response Date
Informed about importance of tree trimming work	45.3%	48.2%
Notified about planned tree trimming work	35.8%	36.3%
Notification satisfaction	88.5%	89.2%
Work quality satisfaction	82.1%	82.7%
Completed as described satisfaction	76.6%	77.7%
Removed woody debris satisfaction	82.1%	83.5%
Overall Satisfaction	**82.1%**	**83.5%**

Source: DR 706.

4. Although it performs considerable outreach, PSEG LI does not currently measure the effectiveness of its communication efforts with respect to low income programs and customers.

- The promotion and administration of PSEG LI’s income assistance programs are the responsibility of multiple organizations: two organizations within PSEG LI’s Customer Operations Department and Lockheed Martin, an external contractor managing PSEG LI’s energy efficiency programs. The relevant PSEG LI organizations are depicted in **Exhibit XII-5**.

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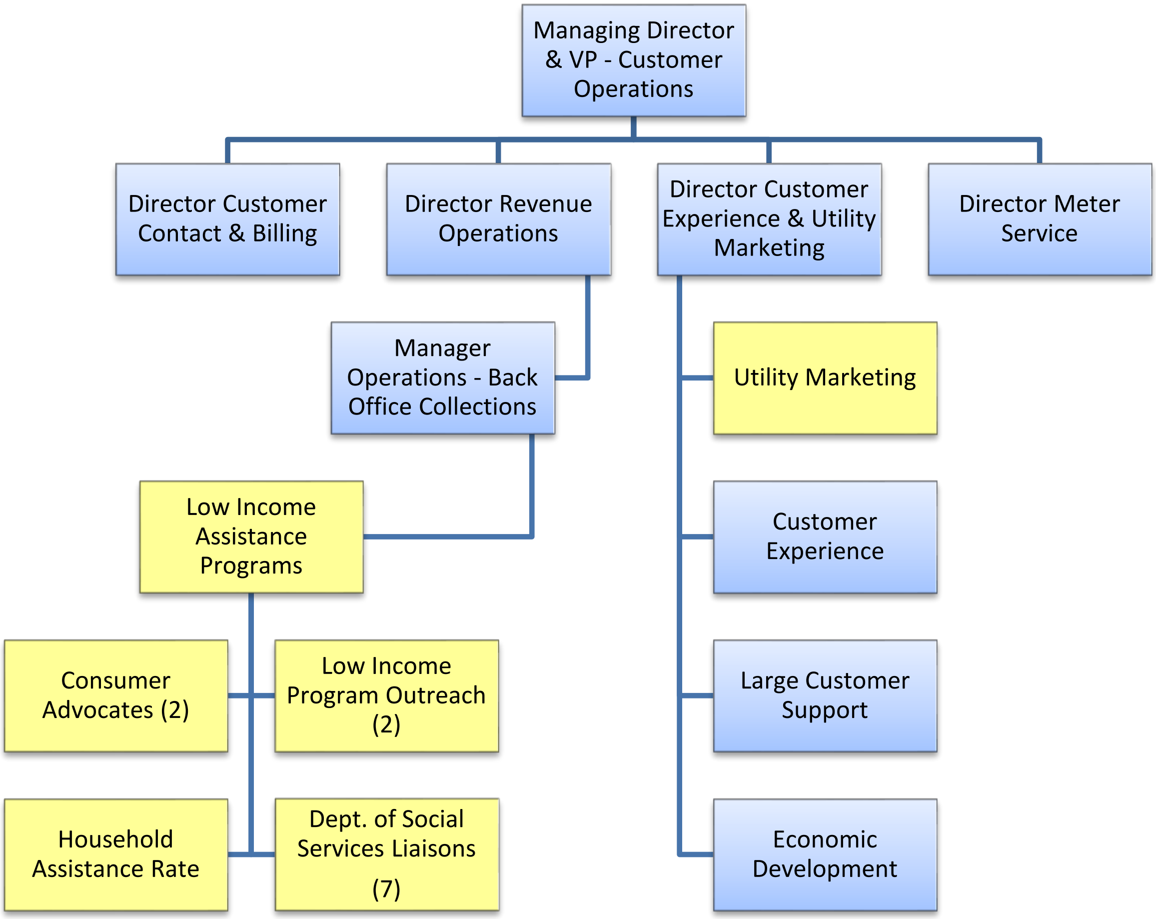
[38] DR 705 Attachment 4

[39] DR 705 Attachment 8

[40] DR 705 Attachment 5, April – December 2016.

Exhibit XII-5
Low Income Assistance Program – PSEG LI Organizations



Source: DR 2 Attachment 1, IR 211.

– PSEG LI Consumer Advocates work with individual customers to help them apply for financial assistance from PSEG LI and social service agencies. The Consumer Advocates spend four days of their work week in different agencies (e.g., Department of Social Services (DSS), United Health Care, Family Service League, and shelters) to provide assistance to customers.[41] Consumer Advocates may also be reached via a phone number listed on bill inserts and program materials.

– Utility Marketing provides the communications collateral. Low-income programs are marketed in a variety of ways: on PSEG LI's website and through social media posts, direct mailings regarding the Residential Energy Affordability Partnership (REAP) program and income eligibility, REAP and financial assistance program brochures, email blasts, bill inserts and newsletters.[42]

- Lockheed Martin administers the REAP program as part of PSEG LI's energy efficiency program contract with Lockheed Martin. Energy efficiency marketing costs are part of Lockheed Martin's budget and not part of PSEG LI's Utility

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[41] IR 211, DR 940 Attachment 1
[42] DR 900 Attachments 1-17

Marketing budget. REAP is marketed in a variety of ways. About 10,000 information post cards are sent to low-income area zip codes, and the program includes other informational materials. An Outreach Specialist delivers presentations at various events. It is also promoted at PSEG LI Community Partnership Program events. Contractors conducting the energy audits will also leave door hangers on neighboring houses.

- **Exhibit XII-6** provides details of the various assistance programs available to income-eligible customers.

Exhibit XII-6
Income Assistance Programs

Program	Description	Responsible Organizations
Home Energy Assistance Program (HEAP)	A federally-funded grant to assist with the payment of energy bills. There are two types of HEAP grants - "Regular" and "Emergency". Customers may qualify for one or both depending on their financial situation.	PSEG LI Utility Marketing provides marketing collateral.
Residential Energy Affordability Partnership (REAP)	REAP offers lower-income customers a free home energy survey, energy saving tips, and may include the installation of energy savings measures.	Administered by Lockheed Martin. REAP also marketed through networking with social service agencies and other events. Lockheed Martin and PSEG LI Utility Marketing provide marketing collateral.
Household Assistance Rate	Provides a lower rate to customers participating in select other assistance programs (e.g., food stamps, HEAP, Medicaid, Public Assistance).	PSEG LI Utility Marketing provides marketing collateral.
Emergency Assistance	Emergency assistance for households experiencing temporary financial difficulties.	Department of Social Services (DSS) administers the program. PSEG LI Utility Marketing provides marketing collateral.
Project Warmth	A one-time grant for fuel, plus an additional amount for fuel-related electricity, from a non-government island-wide fuel fund.	United Way of Long Island administers program. PSEG LI Utility Marketing provides marketing collateral.
Consumer Advocates	PSEG LI Consumer Advocates guide and help customers apply for financial assistance from PSEG LI and social service agencies.	PSEG LI Low Income Program and Advocacy area within Back Office Collections.

Source: https://www.psegliny.com/files.cfm/brochure-FA1.pdf, IR 217, DR 828 Attachment 1

- In addition to the programs listed in **Exhibit XII-6**, through Lockheed Martin, PSEG LI - offers lower income customers extra benefits under the Home Performance Program (for electric heat customers) and Home Performance with Energy Star (for oil/propane customers). For all customers, PSEG LI will cover the cost of 15 percent of the measures installed, up to $3,000. For customer at or below 80 percent of an area's median income, PSEG LI will cover 50 percent of the costs, up to $4,000. For customers at or below 60 percent of the state median, 100 percent will be covered up to $4,000.[43] The Home Energy Analyzer on PSEG LI's website is one of the primary marketing tools for the Home Performance programs.

- Customer Advocates within the Low Income Assistance Program group promote the income assistance programs identified in **Exhibit XII-6** to customers experiencing

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[43] IR 217

financial difficulties. They also promote the programs with various local and regional consumer advocates throughout PSEG LI's service territory. On a quarterly basis, they provide quarterly newsletters to over 300 consumer advocates. The newsletters provide information on PSEG LI's programs and services, Consumer Advocate on-site schedule, energy savings tips and information on upcoming events.[44]

- Programs are generally cross-promoted.
  - During the REAP Program Site visits, customers are provided with an information pack that includes PSEG LI's Financial Assistance Brochure (HEAP, Emergency Assistance, Household Assistance Rate), the Caring Brochure (special protection for medical emergencies, critical care program, etc.), 66 Ways to Save Energy, an Energy Savings Program Guide, a Household Assistance Rate Application and a Project Warmth flyer.[45]
  - REAP is included in the various financial assistance program materials but other energy efficiency benefits are not. The materials also do not include information on other ways to save (i.e. 66 Ways to Save Energy).
  - Customers participating in the Home Performance Program do not receive information on other programs.[46]

- PSEG LI is able to provide information on participation levels, but does not have data regarding saturation levels or other measures of low income program marketing/outreach effectiveness.[47]
  - Participation levels for Home Performance and REAP combined are about 4,000 to 5,000 customers.[48] In 2017 PSEG LI conducted 1,921 REAP visits.[49]
  - The REAP Program Outreach Specialist attended roughly 100 events in 2017.[50] Seventy-six had been completed by early November. The REAP Program had also been promoted at more than 400 Community Partnership Program events.
  - The energy efficiency programs (including REAP) have monthly and annual participation, MW and MWh goals.[51]
  - PSEG LI has taken over 1,025 actions in the form of agency partnerships, tabling events, presentations, training and information packets distributed. PSEG LI considers the effectiveness of these events based on the number of community advocates or customers in attendance and how well the information is received.[52]
  - As of October 16, 2017, 17,923 customers were enrolled in the Household Assistance Rate.
  - PSEG LI is not aware of any surveys of low-income customers regarding their awareness of PSEG LI's service offering or the services they are looking for.[53]

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[44] DR 940 Attachments 3-6
[45] DR 998 Attachments 1-10
[46] DR 998
[47] DR 900, IR 217
[48] IR 217
[49] DR 998
[50] DR 998 Attachment 12
[51] DR 998 Attachments 13-15
[52] DR 900, DR 0808 Attachment 4
[53] DR 900

- While not targeted at the low-income programs, various surveys and market research indicate that PSEG LI customers are not very familiar with the utility's energy efficiency programs and do not have a strong unaided recall of advertising efforts.

5. PSEG LI trains its employees to enable them to enhance and improve outreach.

- New Customer Service Representatives (CSRs) and collections field representatives receive training on PSEG LI's low-income and customer advocacy programs.[54] The Low Income Program group provides training for PSEG LI personnel and promotes the low-income and payment assistance (e.g., medical needs and critical care, peace of mind programs).[55]

- Training educates PSEG LI employees on the various financial assistance programs available to customers.[56] As part of the bi-annual training conducted by the Payment Assistance Outreach Coordinator/Assistant within the Low Income Assistance Programs group, financial assistance program handouts are distributed to customer facing departments such as CSRs, Field Collections, and the Customer Offices.[57]

- Capital project fact sheets are provided to the contact center, customer offices and communications to assist them in addressing customer inquiries. The fact sheets provide a description of the project, the proposed schedule, anticipated traffic interruptions and power outages, project route (where applicable), and information on tree trimming, pole height, double wood and undergrounding.[58]

- The contact center is also provided with a vegetation management job aid and received training on the vegetation management program.[59]

- All of the current External Affairs District Managers were previous National Grid or LIPA employees or have a background in government affairs.[60] New DMs receive training in the various systems used (i.e., geographic information system (GIS), PCall, Engines), utility operations, key departments, and external affairs-specific training covering such items as the External Affairs Handbook, the current capital project five-year plan, sample communications, the capital project scoring process and closeout, FEMA projects, vegetation management projects, municipal liaison/storm training and the IRP.[61] New DMs also shadow experienced DMs in the field.

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[54] DR 828 Attachment 1, IR 211

[55] IR 211, DR 940

[56] DR 828 Attachment 4, IR 211

[57] DR 828 and Attachments 2 and 3

[58] DR 888 Attachments, DR 801 and Attachment, DR 976-977

[59] DR 705 Attachments 6 and 7

[60] IR 190, 191, 203, 204, 205

[61] IR 204, LIPA/PSEG-LI Fact Verification (External Affairs Department Onboarding Training)

6. **NorthStar performed an assessment of PSEG LI's website in November 2017 and found it to be user friendly and informative, although some links in web page were not functioning.**

   - A survey of utility customers conducted from December 2015 to late January 2016, placed PSEG LI's website in the third quartile among other utility companies.[62]

   - NorthStar reviewed PSEG LI's website in November 2017 and found it to be above average for user friendliness, organization, and in providing customers and stakeholders with necessary functionality. **Exhibit XII-7** provides details on the results of NorthStar's review, including opportunities for improvement. PSEG LI's website presentations of reliability projects are discussed in Conclusion 8.

Exhibit XII-7
NorthStar Assessment of www.psegliny.com

Criteria	Discussion
Design	The website utilizes top horizontal navigation. First impressions of the website suggest a clean look with appearance of ease of navigation with structured information sections. A home site index is not visible but can be accessed through the search area.
Navigability: Navigation Tabs • For Home • For Business • Outage Center • Community • About Us • My Account Login	The main landing page defaults to the last tab "My Account Login" and buttons across the top of the webpage allow quick access for customers to pay bills, report an outage, or contact the utility. Each of the navigation tabs populates a directory where information can be accessed by clicking on word links. A left-hand navigation menu is not populated in the situation if a subject heading link is selected. If a topic under a subject heading link is selected a left-hand navigation menu is populated most of the time. The bottom of the webpage displays the same named headings as the main navigation tabs with the category headings matching the horizontal menu drop-down categories subject areas. Some text is illegible due to border overlapping. There appears to be some disconnect between web pages in relation to a formal subdirectory and directory hierarchy. This creates a mismatch between what information one would expect to be on a webpage and what is displayed. For example, the "For Home" tab has "Understand Your Bill" as a topic under the "My Account" subject area. Selecting "Understand Your Bill" launches four areas: • Your PSEG Long Island Bill • Bill Inserts • Estimated Billing • Frequently Asked Questions However, if one attempts to navigate to the "Understand Your Bill" subject area by first selecting the higher level "My Account" heading, the webpage displayed does not depict the same four areas and navigation to these areas is not intuitive.
Dates	All webpages have a last updated date appearing in the lower right corner. This is important to maintain as customers should be aware of how recent the information displayed is.
Content/Relevance	PSEG LI has done a good job in creating a self-service portal and providing an information repository within their website. A notification area with the latest updates would be one way to encourage customers to review more information on the website. As it stands now, a customer visiting the website to follow-up on an issue is not enticed to pursue additional information. Some suggested areas of improvement: • Include a webpage to state mission, values, goals, service provided, and in addition

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[62] DR 109 Attachment 26

Criteria	Discussion
	to map of service territory. • Add a notification area where customers can see latest information updates. • More emphasis on current happenings such utility initiatives and community events as these are somewhat hidden under the “About Us” area.
Special Programs	Customer programs such as rebates and incentives, critical care program, financial assistance programs (HEAP, Household assistance rate, REAP, Project Warmth), as well as other programs such as Critical Care Program, Peace of Mind Program, Friendly Follow-up, and information on customer special protections can be found by searching different pages on the website but are not consolidated in a centralized location nor are these accessible immediately under a top level navigation tab located on the home page. The decentralized approach impedes customers from learning about all programs which may be applicable to them. It is recommended that a centralized approach where the website draws more attention to Rebates and Incentives as well as all customer program offerings discussed in the Customer Programs / Special Programs section. Having available phone number and a downloadable/webform application to streamline the process would be preferable.
Language Access	No other languages available for website translation.

Source: NorthStar Analysis, www.psegliny.com

- E Source, a research and consulting firm specializing in utilities, issued its 2017 Review of U.S. Electric and Gas Company Websites in late July. E Source assessed 114 U.S. and Canadian utility websites based on customer interactions, rating the most essential online tasks accessed from desktop and mobile devices, including overall design, usability, and relevance of customer information and online customer service opportunities. E Source ranked PSEG LI’s website second in the Northeast and seventh in North America.[63]

7. **PSEG LI External Affairs has a defined approach for organizing, planning and executing its outreach activities to align with the five-year capital plan; however, the capital project outreach could be more robust, as discussed in Conclusion 8, and the process by which the required amount of outreach is determined is somewhat subjective.**

- In 2014, External Affairs created a handbook and associated processes to provide a consistent, coordinated approach to outreach for capital projects. PSEG LI researched other utilities and found there was no defined approach for handling external affairs outreach. PSEG LI generally follows the handbook, but it is specific to capital projects and does not all aspects of external affairs.

- The assignment of DMs to geographic areas allows them to foster relationships with elected officials and their staff, government agencies and other stakeholders.[64] There are about 900 separate governments on Long Island.[65]

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[63] DR 941 Attachment 1 (filed on SharePoint with the response to DR 943)

[64] IR 68, DR 302

[65] IR 68

- The External Affairs District Managers work with capital Project Managers to determine outreach requirements, so that requirements are developed based on both an understanding of the project and knowledge of the community. **Exhibit XII-8** provides a summary of the activities involved in the capital project planning process, with outreach-related elements highlighted. The Public Outreach Plan required during the planning phase is effectively a checklist of the outreach activities to be completed.[66]

Exhibit XII-8
Planned 2017 Key Project Milestones – Phase 1 and 2 [Note 1]

Milestone	Definition/Owner
Phase 1: Planning	
Scope Document Fully Signed Off	The Scope Document has been fully signed off (this milestone deliverable is expected to be completed at the **end of study estimate level** of the project development) **Owner:** Planning & Construction (P&C) (Project Management)
URB 60% Office Level Estimate Approval	URB has approved the 60% Office Estimate and Funding **Owner:** P&C (Project Management)
Public Outreach Plan Finalized	Public Outreach team has completed the Project Specific Outreach Plan (this means public outreach team has completed the public outreach plan for the project) **Owner:** External Affairs (Public Affairs)
URB 65% Study Level Estimate Completed and Approved	65% study estimate completed by Project Controls Engineer & approved by the Project Manager **Owner:** P&C (Project Controls)
URB 70% Conceptual Level Estimate Completed and Approved	70% Estimate completed by Project Controls Engineer & approved by the Project Manager **Owner:** P&C (Project Controls)
Complete Project Execution Plan	Complete Project Execution Plan for Projects estimated greater than **$8,000,000** (schedule, scope, and estimate) **Owner:** P&C (Project Management)
NEDLI Input is Initiated into the System	Establish WBS and tag projects in SAP **Owner:** P&C (Project Controls)
URB 90% Study Level Estimate Completed and Approved	98% Estimate completed by the Project Control Engineer and approved by the Project manager. **Owner:** P&C (Project Controls)
Phase 2: Design and Engineering	
Populate Equipment Spreadsheet with initial project information	Populate the Long Lead Material report with initial project info at project inception **Owner:** P & C (Project Management Engineer)
Determine Design Model	Determine if Design will be done In-House or by Consultant **Owner:** Planning, Resources and Engineering

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[66] DR 939 and Attachments

Milestone	Definition/Owner
Pre-Construction Public Outreach is Complete	Concept Layout has been presented by Public Affairs to all involved parties & the layout is acceptable in accordance with the project outreach plan. In addition, all required tasks identified in the project outreach plan up to preconstruction stage have been completed. **Owner:** External Affairs
All Property Rights Secured	Corporate Properties has secured all Property Rights for the project **Owner:** Planning, Resources and Engineering (Real Estate)
Civil Construction Design Package Issued for Construction	Civil design drawings & specifications have been issued for Construction **Owner:** Planning, Resources and Engineering (Civil Engineering)
Overhead Transmission Construction Design Package Issued for Construction	Overhead Transmission design drawings & specifications have been issued for Construction **Owner:** Planning, Resources and Engineering (Overhead Transmission Engineering)
Underground Transmission Construction Design Package Issued for Construction	Underground Transmission design drawings & specifications have been issued for Construction **Owner:** Planning, Resources and Engineering (Underground Transmission Engineering)
Substation Transmission Construction Design Package Issued for Construction	Substation design drawings & specifications have been issued for Construction **Owner:** Planning, Resources and Engineering (Substation Engineering)
Distribution Construction Design Package Issued for Construction	Distribution design drawings & specifications have been issued for Construction **Owner:** OH / UG Lines (Distribution Design Engineering)
Protection Construction Design Package Issued for Construction	Controls design drawings (schematics & wiring diagrams) have been issued for Construction **Owner:** Planning, Resources and Engineering (Controls & Protection Engineering)
Long Lead Equipment Purchase Requisitions Issued to Procurement	The date that the last purchase requisition has been issued to Procurement for major equipment **Owner:** Planning, Resources and Engineering (Engineering)

Note 1: Activities may not be completed in the order specified above, and could be completed along a parallel path. The Project Manager is responsible for determining which key milestones are to be used and when they are scheduled. Phase 3-6 are not shown as they do not involve External Affairs.
Source: DR 939, DR 871 Attachment 1.

- Major capital projects are evaluated and scored as Tier 1, 2 or 3 by the respective External Affairs DMs based on perceived risk.[67] The project justification documents (PJDs) submitted to the Utility Review Board for project approval include the External Affairs tier risk score. The tiers are used to determine the level of outreach required.[68] The External Affairs Project Handbook sets forth the general requirements and the process used to complete the risk scorecard. The scorecard considers a number of risk categories and specific criteria and results in a numerical score assigned to the project as shown in **Exhibit XII-9**. The scoring process seems reasonable, but is subjective as it is based on each DM's understanding of the project, the project site (in terms of environmental impacts and historical significance), and the potential response of the community and other stakeholders to the project.

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[67] IR 68
[68] DR 322, IR 068, 190

Exhibit XII-9
Capital Project Perceived Risk Scoring

Assessment Area	Number of Criteria	Maximum Points
Project Need	7	11
Community Impacts	6	12
Government Dynamics	9	18
Media	5	10
Permits and Regulatory Requirements	7	7
Aesthetic Impacts	3	4
Environmental	2	2
Historical/Cultural	4	4
Construction Considerations	9	9
Max Total		**77**
Tier Levels		
Tier 1		1-15 points
Tier 2		16-39 points
Tier 3		40-77 points

Source: DR 322.

- Tier 1 projects are considered to be fairly straightforward; a significant external affairs strategy is generally not required. Tier 1 projects should have a fact sheet and be included in the annual briefings with officials.[69]
- Tier 2 projects are considered to have an intermediate amount of challenges and may require greater outreach. In addition to the briefing and fact sheet, Tier 2 projects should have a customer letter, website reliability page posting, a project timeline and route maps.[70]
- Tier 3 projects are considered complex and more likely to generate controversy, and as such require greater outreach. In addition to the required Tier 2 items, Tier 3 projects should have a public information session and targeted social media. [71]

- PSEG LI's External Affairs group prepares a five-year outreach plan based on the five-year capital plan.[72] Each District Manager provides an annual briefing to the various, villages, towns and unincorporated areas within their District. The briefings provide information on PSEG LI accomplishments in the prior year, address the projects that are part of the 5-year capital plan, provide information on PSEG LI's vegetation management program, and other key topics such as the IRP.[73]

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[69] DR 322, DR 885 Attachment 1, DR 943 Attachment 1
[70] DR 322, DR 885 Attachment 1, DR 943 Attachment 2
[71] DR 322, DR 885 Attachment 1, DR 943 Attachment 3
[72] DR 323, Attachment 1
[73] DR 887 Attachments 3 and 4

8. PSEG LI's capital project outreach program may not provide adequate information regarding higher risk capital projects.

- According to PSEG LI, the External Affairs Handbook does not dictate the specific set of outreach activities required for a given scorecard tier to allow District Managers flexibility to develop an outreach strategy appropriate for each project.

- Although required by the External Affairs Handbook, PSEG LI does not consistently take notes "memorializing" meetings/briefings with impacted officials.[74] Beginning in late 2017/early 2018, PSEG LI began emphasizing the need for documentation.[75]

- During the period 2014 to 2017, PSEG LI only held a small number of public meetings, as shown in **Exhibit VII-10**.[76]

Exhibit VII-10
Public Meetings Held for Capital Projects

Project	Description	Ext. Affairs Ranking	Public Meeting Date	Projected/ Actual Construction Dates
Kings Highway Substation	Installation of a new 3 bank 138/13kV substation on Rabro Drive in Hauppauge, NY, and associated transmission and circuits. The office estimate was $28.4 million.[77]	Tier 3	11/28/2017	Winter 2018 (Demolition)
Berry Street Substation, Reconductoring, Conversion and Reinforcement	Installation of a new substation in the Town of Babylon, reconductoring the transmission line along the LIRR right-of-way and work on the distribution lines.	Tier 3	9/7/2016	Start: Mid-2015 End: 2017
New overhead transmission circuit in East Garden City	Replacement of a section of underground cable in East Garden City with a new overhead transmission circuit. Seventeen distribution poles (35-45 feet in height) were replaced with transmission poles (65-79 feet in height). The public meeting presentation addressed the pros and cons of the planned replacement and two alternatives – repairing and replacing the underground cable.	NA	4/1/2015	Start: April 2015
New Underground Submarine Feeder Cable	Installation of a new underground submarine feeder cable from Greenport to Shelter Island. The public information session provided information on the proposed plan, directional drilling equipment, the project timeline, and environmental and impacts and associated mitigation	Tier 3	9/20/2016	Start: October 2017 End: By May 15, 2018

Source: https://www.psegliny.com/page.cfm/AboutUs/CurrentInitiatives/ReliabilityProjects/KingsSubstation, DR 647 Attachment, DR 726 Attachment 26, DR 885 Attachment 1, DR 888 and all Attachments DR 1003 and all Attachments.

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[74] DR 322 Attachment 1, review of project materials and various interviews

[75] LIPA/PSEG LI Fact Verification

[76] DR 888 and Attachments, DR 1003 and Attachments

[77] DR 726 Attachment 26, DR 1003 and Attachment

- Public meeting/open house notices are generic and do not provide customers with details of the project. The letter for the substation on Rabro Drive contained the following notice. Recent notices contain similar language.[78] The public information sessions themselves include site maps, consideration of alternatives, renderings, and a comparison of electromagnetic fields (EMF) from substations and household items.[79]

> "PSEG Long Island invites you to join us for an informational open house about planned electrical work in your community. To keep pace with the growing demand for electricity, PSEG Long Island is making critical system upgrades in your area. This work will minimize the risk of future electric service disruptions, improve your power quality, and harden the equipment serving your home or business against extreme weather like heat waves and storms.
>
> Please join us on … PSEG Long Island representatives will be on hand to provide an overview of the planned work…"[80]

- Letters to affected customers are based on a standard template.[81] **Exhibit XII-11** provides a sample letter.

  - Letters do not include a link to the reliability portion of PSEG LI's website.
  - Letters do not consistently provide customers with specific details regarding when construction will occur or the details on road closures and traffic issues.[82] However; customers are always notified of road closures through automated phone calls, flaggers and cones.[83]
  - Letters do not include maps, schematics, pictures or illustrations, and the level of detail varies. Letters and fact sheets do not consistently include the heights of existing or new poles.[84]

- PSEG LI's website provides more details regarding the PSEG LI reliability projects; however, this information is not advertised and is not easy to locate.

  - Letters to customers about specific capital projects instruct customers to call the contact center if they have questions. They do not include a reference to the website.
  - The PSEG LI website landing page does not contain an obvious link for capital project or reliability information. At the bottom of the landing page under "For Home" there is a link for "Safety & Reliability."[85] That page provides information on tree trimming, reliability projects and electric safety.[86]
  - The customer letters and fact sheet form the basis for the website reliability project postings and provide limited additional information. For some projects there are links to "visualizations"; however, the links are not currently functioning.[87] Community meeting presentations are included, but the website does not indicate when the information was posted.

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[78] DR 888 Attachments

[79] North Lindenhurst DR 0888 Attachment 8

[80] DR 1003 Attachment 1

[81] DR 800, 888

[82] DR 801, 887, 888 and associated Attachments.

[83] LIPA/PSEG LI Fact Verification

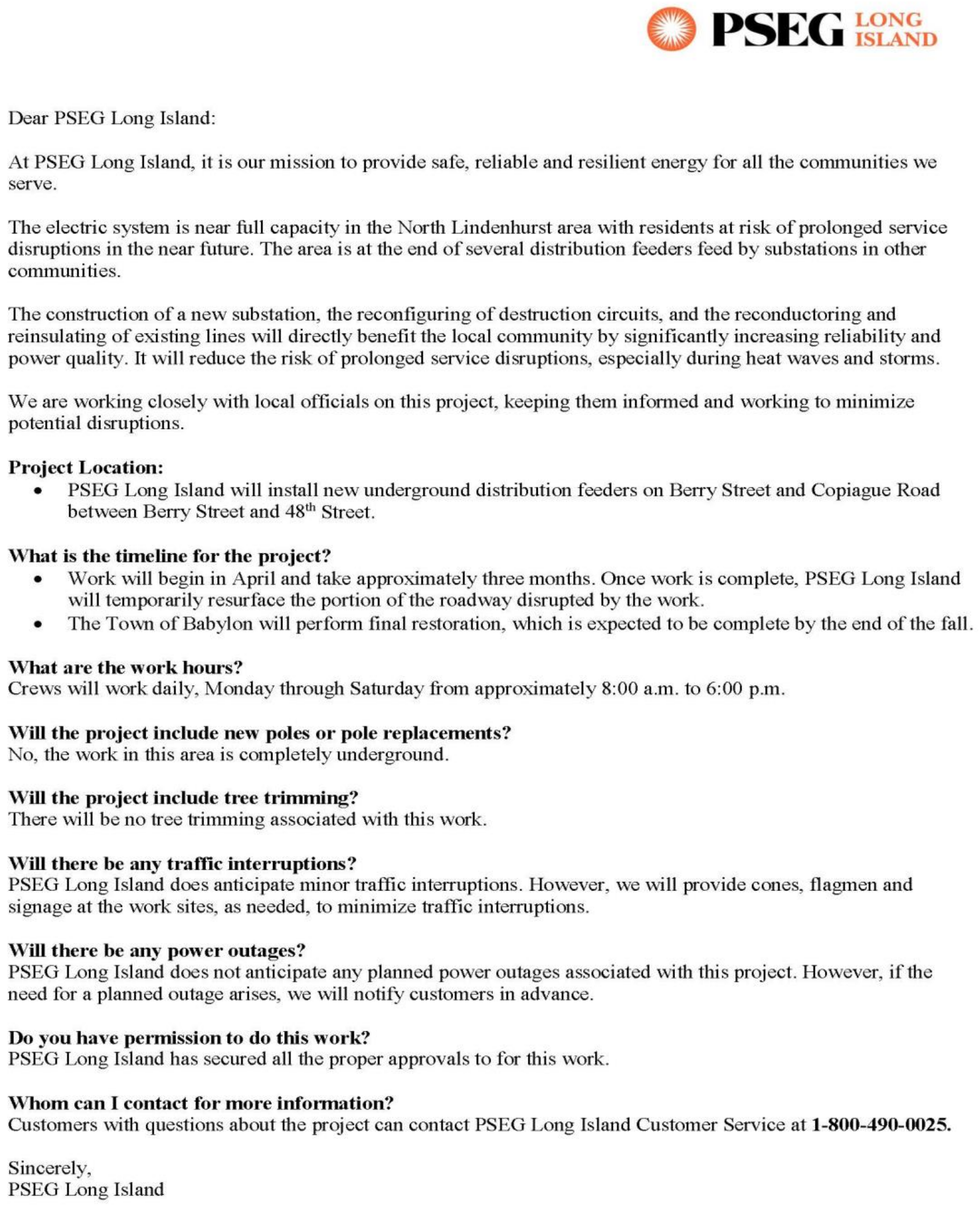
[84] DR 887 Attachment 1

[85] https://www.psegliny.com/

[86] https://www.psegliny.com/page.cfm/Home/Safety

[87] DR 801 and Attachments, DR 888 and Attachments, www.psegliny.com

Exhibit XII-11
Sample Capital Project Customer Letter



PSEG LONG ISLAND

Dear PSEG Long Island:

At PSEG Long Island, it is our mission to provide safe, reliable and resilient energy for all the communities we serve.

The electric system is near full capacity in the North Lindenhurst area with residents at risk of prolonged service disruptions in the near future. The area is at the end of several distribution feeders feed by substations in other communities.

The construction of a new substation, the reconfiguring of destruction circuits, and the reconductoring and reinsulating of existing lines will directly benefit the local community by significantly increasing reliability and power quality. It will reduce the risk of prolonged service disruptions, especially during heat waves and storms.

We are working closely with local officials on this project, keeping them informed and working to minimize potential disruptions.

Project Location:

- PSEG Long Island will install new underground distribution feeders on Berry Street and Copiague Road between Berry Street and 48th Street.

What is the timeline for the project?

- Work will begin in April and take approximately three months. Once work is complete, PSEG Long Island will temporarily resurface the portion of the roadway disrupted by the work.
- The Town of Babylon will perform final restoration, which is expected to be complete by the end of the fall.

What are the work hours?
Crews will work daily, Monday through Saturday from approximately 8:00 a.m. to 6:00 p.m.

Will the project include new poles or pole replacements?
No, the work in this area is completely underground.

Will the project include tree trimming?
There will be no tree trimming associated with this work.

Will there be any traffic interruptions?
PSEG Long Island does anticipate minor traffic interruptions. However, we will provide cones, flagmen and signage at the work sites, as needed, to minimize traffic interruptions.

Will there be any power outages?
PSEG Long Island does not anticipate any planned power outages associated with this project. However, if the need for a planned outage arises, we will notify customers in advance.

Do you have permission to do this work?
PSEG Long Island has secured all the proper approvals to for this work.

Whom can I contact for more information?
Customers with questions about the project can contact PSEG Long Island Customer Service at **1-800-490-0025.**

Sincerely,
PSEG Long Island

Source: DR 888 Attachment 3.

9. LIPA and PSEG LI are generally aware of applicable external affairs issues and outreach efforts.

- PSEG LI serves as the face of the utility and has increased the focus on communications and responsiveness with the media, customers, elected officials and other stakeholders.

- A lobbyist works with PSEG LI's External Affairs organization to keep it apprised of potential regulatory changes. Information is then disseminated to senior leadership.

- Bi-weekly joint leadership meetings provide for an exchange of information between LIPA and PSEG LI.[88] NorthStar observed one such meeting where potential capital project external affairs issues were discussed.

- Project Managers from PSEG LI Engineering/Planning & Construction work with External Affairs DMs in the evaluation and scoring of projects. External Affairs ranks the projects when the preliminary design phase is complete and before they are sent to the URB for approval. See **Chapter IX - Program and Project Planning and Management** for additional discussion of the URB process. The regional PMs and the associated External Affairs DM meet on a weekly basis to review project status.

10. Outreach costs associated with individual capital projects are budgeted and tracked at the cost element level. NorthStar selected a sample of projects for review, but due to a reporting anomaly could not perform a comprehensive comparison of budget to actual outreach spending for capital projects. Outreach budgets for specific capital projects were not developed for 2016.

- External Affairs has an internal budget for its day-to-day outreach activities. **Exhibit XII-12** provides the budgets and actuals from 2014-2017.

Exhibit XII-12
External Affairs Budget and Actual Expenses

Year	Budget	Actual	Variance [Note 1]
2014	$ 974,364	$ 613,926	$ 360,468
2015	1,166,132	757,792	408,340
2016	1,236,595	1,056,836	179,758
2017	848,860	[Note 2]	

Note 1: Variances due to greater than anticipated time spent on outreach for capital projects and vacant positions during part of each year.
Note 2: 2017 Actual expenses not available at the time this report was prepared.
Source: DR 798.

- In addition to its internal budget, External Affairs direct charges or allocates costs for outreach to specific capital projects. **Exhibit XII-13** provides External Affairs costs charged to capital projects.

Exhibit XII-13
External Affairs Charges to Capital Projects – Actual 2015 - 2017

	2015	2016	2017 through July
Direct Cost Only	$ 20,931	$ 62,005	$ 36,057
Burdens/Assessments	356,387	534,528	196,958
Total	**$ 377,318**	**$ 596,533**	**$ 233,015**

Source: DR 325 Supplemental.

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[88] IR 67

- External Affairs tracks performance against its own budget, but is not responsible for the capital project outreach budgets.[89]
    - Each year the External Affairs team reviews the major planned capital projects budgeted for that year. Based on the outreach score, number of impacted municipalities, and experience with similar projects, External Affairs estimates the number of labor hours to be spent developing and conducting outreach for planned projects. These hours are included in the labor budget for each project. They are not included in the External Affairs budget.
    - Costs for customer mailings typically do not exceed $1,000 for a typical project, and these costs are folded into the overall services budgets for each project.
    - According to PSEG LI, other outreach costs have been minimal.

- Funding requests provided to the Utility Review Board include the public outreach ranking, but do not specify the outreach budget. Funding request budgets are at a very high level.[90] Project justification documents also do not specify the outreach budgets. Once the project has been approved project costs are generally reviewed in aggregate.

- NorthStar selected a sample of projects for review. **Exhibit XII-14** provides details from that review. PSEG LI is not certain as to the cause, but no outreach-related budgets were identified for these projects in 2016; however, outreach costs were incurred in 2016.[91] External Affairs does not recall an instance when they have been notified that they were over budget.

Exhibit XII-14
Selected Capital Projects – Plan and Actual 2015 – 2017

Code	Project Name	Tier	Type	Total Project 2015-2017		Outreach-Related 2015-2017	
				Plan / Budget ($000)	Actuals ($000)	[Note 1] Plan/ Budget ($)	Actuals ($)
L.89311	Berry - Lindenhurst	3	Load Growth	$14,587	$5,625	$38,584	$9,343
L.99311	Berry - Lindenhurst	3	Load Growth	$27,793	$18,747	$32,103	$178,116
L.99021	Eastport	2	Load Growth	$18,537	$27,116	$11,342	$104,070
L.99617	East Garden City		Regulatory	$7,660	$1,381	$0	$2,146
L.89501	Southold-Shelter Island	3	Load Growth/ Reliability	$62,789	$4,453	$149,848	$74,095
L.99407	Southold-Shelter Island			$0.00	$5,184	$0	$0

Note 1: No outreach planned costs for the projects were included in SAP in 2016, limiting the usefulness of the data for performing budget versus actual calculations. Actual costs are a very small portion of the total capital project cost.
Source: DR 888.

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[89] DR 325 Supplement and DR 1002
[90] DR 760 and Attachments
[91] January 29, 2018 phone call

D. RECOMMENDATIONS

1. Measure the effectiveness of capital-project outreach, media relations and external affairs programs, to determine whether outreach efforts are cost-efficient, on target, and achieving results. Potential measurement options include surveys, focus groups, a media clip index, or attendance at public meetings.

2. On a pilot basis, evaluate the potential use and effectiveness of text messages and phone calls to customers on scheduled tree trim routes.

3. Measure the effectiveness of energy efficiency and low-income program outreach and marketing efforts.

4. Develop a more formalized process for determining the outreach budgets for capital projects, particularly Tier 3 and high scoring Tier 2 projects.

5. Update the External Affairs Handbook to reflect recent lessons learned, the findings in NorthStar's report, the items cited below, and the other recommendation cited in this chapter.

   - Expand the discussion of project scoring.

   - For all Tier 3 projects, update constituents as the project approaches its start date, or if there are significant project changes (e.g., scope, schedule, location/route, duration, or other item likely to impact the community such as overhead versus underground, pole heights, additional poles, traffic, outages). This is in addition to the annual update on the 5-year capital plan.

6. Formalize the External Affairs training and enhance it to include the following:

   - Outreach expectations and requirements (e.g., frequency and information to be communicated)
   - Scoring methodology and application of the scoring rubric in a consistent, objective manner
   - Documentation requirements
   - The External Affairs Handbook and other policies and procedures
   - Communication with the DPS
   - When various outreach activities/communications methods are required or should be employed
   - Developing budgets for capital project outreach.

7. Develop formal public outreach plans for each Tier 3 project (i.e., not a spreadsheet). At a minimum the plans should include the following, and should be updated as the project or anticipated outreach requirements change:

   - Description of the project, including timeline and key milestones
   - Checkpoints to identify any significant changes in project scope or timing
   - Scoring sheets and a discussion of key concerns and how to mitigate them
   - Discussion of alternatives considered
   - Project budget and detailed outreach budgets

- Anticipated frequency of communications/timeline, planned outreach activities and materials.

8. Document meetings (date, attendees, topics discussed, takeaways) with impacted officials as required by the External Affairs Handbook.

9. Increase the specificity of capital project-related outreach:

- Include more specific, detailed project information on public information meeting letters and notices.
- All outreach materials (i.e., fact sheets and customer letters) resulting in additional poles, pole changes, a shift from underground to overhead cables should indicate such and provided detailed description.
- Consider increased use of pictures and renderings in outreach materials, particularly the reliability web pages.
- Add a link to PSEG LI's reliability web page on all outreach materials, particularly customer letters. Include dates materials were added to the reliability project pages of PSEG LI's website.
- Consider an icon for "Upcoming projects in your neighborhood" or the equivalent to the www.psegliny.com landing page.
- Include community/public meeting presentations on the reliability pages of PSEG LI's website.

XIII. PERFORMANCE AND RESULTS MANAGEMENT

This chapter provides the results of NorthStar's review of the Amended and Restated Operating Service Agreement (A&R OSA) metrics and PSEG LI's performance management processes.

A. BACKGROUND

Performance management is an ongoing process that consists of performance planning, measurement, review, feedback and corrective action. Key elements of performance management include the design of appropriate metrics and targets; monitoring, reporting and communication, and the design and implementation of an appropriate employee performance review process which links employee objectives and performance targets to achievement of overall corporate goals and objectives. Measures should be meaningful and appropriately linked to the organization's mission, objectives, and strategic and operational plans. Performance should be reviewed and adjusted in a timely manner.

A&R OSA Metrics

The A&R OSA established performance metrics to measure PSEG LI's performance against operational and customer satisfaction goals. The A&R OSA also established an Incentive Compensation Pool for each contract year, to be paid to PSEG LI based on favorable performance relative to the performance metrics. The initial set of performance metrics were set forth in the A&R OSA and are listed in **Exhibit XIII-1**.[1] On December 31, 2013, the New York Public Service Commission (PSC) Emergency Response Performance metrics were added to the A&R OSA as Appendix 13.[2]

As shown in **Exhibit XIII-1**, the A&R OSA metrics are defined in four categories, with different weightings for each category:

- Cost Management is a threshold metric. To be eligible for compensation, PSEG LI must not exceed 102 percent of the operating and capital budgets. To be eligible for 100 percent of the potential incentive compensation, PSEG LI must achieve both of the cost management metrics. PSEG LI is eligible for 50 percent if only one of the cost management metrics is met; 0 percent if neither are met.[3]

- Customer Satisfaction, Technical and Regulatory Performance, and Financial Performance.

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[1] DR 4 Appendix 9

[2] DR 4 Appendix 13

[3] DR 4 A&R OSA, Appendix 9, p 2.

Exhibit XIII-1
A&R OSA Performance Metrics 2014

Metric	Base Points	Type	Initial Target (2014)
Cost Management (Threshold)			
Achieve operating budget spending levels		Threshold	<102%
Achieve capital budget spending levels		Threshold	<102%
Customer Satisfaction (47.6%)			
JD Power Residential Survey	10.0	Improvement	542 points
JD Power Business Survey	5.0	Improvement	551 points
After Call Survey Residential	5.0	Improvement	67% satisfied
After Call Survey Business	5.0	Improvement	47.6% satisfied
Personal Contact Survey	5.0	Improvement	83.7% satisfied
Average Speed of Answer (ASA) with Interactive Voice Response (IVR)	7.5	Improvement	79 seconds
Abandonment Rate with IVR	7.5	Improvement	3.8% abandon
Web Transactions Completed	5.0	Improvement	5%
Subtotal	**50.0**		
Technical and Regulatory Performance (28.6%)			
System Average Interruption Duration Index (SAIDI)	10.0	Maintenance	66.2
System Average Interruption Frequency Index (SAIFI)	5.0	Maintenance	0.90
Customer Average Interruption Duration Index (CAIDI)	5.0	Maintenance	84
Occupational Safety and Health Administration (OSHA) Recordable Incidence Rate	5.0	Improvement	1.67
OSHA Days Away Rate	5.0	Improvement	29.81 days
Subtotal	**30.0**		
Cost Management/Financial Performance (23.8%)			
Actual Meter Read Rate	5.0	Improvement	96.8% read
Timely Billing	5.0	Improvement	61.5%
Days Sales Outstanding	5.0	Improvement	41.9 days
Net Write Offs per $100 Billed Revenue	5.0	Maintenance	0.69
Electric Damages per 1,000 Locates		Tracking	
Energy Efficiency (EE) and Renewable Energy (RE) Achieved Load Reduction	5.0	Improvement	60.3
Subtotal	**25.0**		
Total Base Points	**105.0**		

Source: DR 4 A&R OSA Appendix 9, DR 25 Attachment, DR 20 Attachment 2.

Metrics are classified as maintenance or improvement.

- Maintenance metrics are those metrics for which satisfactory performance levels are currently being achieved. The general goal of Maintenance metrics is to incent continued satisfactory performance (generally First Quartile). Each Maintenance metric has a specified “Minimum Performance Level,” a “Points Earned Threshold,” and an “Above Target Performance Threshold.”

- Improvement metrics are those metrics for which current performance is unsatisfactory. The goal of Improvement metrics is to incent improved performance over time. Improvement is measured relative to a “Baseline Performance Level” that represents the starting level of performance, typically 2013 performance. PSEG LI can achieve up to 150 percent of the base points for an improvement metric.

For performance metrics that were not tracked prior to the A&R OSA, the Baseline Performance Level is an average of performance measured during the transition period from National Grid to PSEG LI (as defined in the Transition Services Agreement).

Exhibit XIII-2 provides additional details on how the performance levels and base point multipliers are calculated.

Exhibit XIII-2
Selected A&R OSA Incentive Compensation Provisions

Term	A&R OSA Definition
Maintenance Metrics	
Minimum Performance Level	Level of performance below which potential Incentive Compensation may be reduced.
Points Earned Threshold Performance Level	Level of achieved performance at or above which the Service Provider shall be awarded the Base Points assigned to that Performance Metric.
Above Target Performance Threshold	Level of achieved performance at or above which the Service Provider shall be awarded points at a specified multiple of the Base Points.
Target Range	Range of performance for which the Service Provider will earn 100% of the Base Points.
Below Target Range	A range between the Points Earned Threshold (exclusive) and the Minimum Performance Level (inclusive), in which the Service Provider will earn no points. Although the Service Provider will not earn points for performance in the Below Target Range, such level of performance shall not constitute a failure to perform to the Minimum Performance Level for the subject Performance Metric.
Below Minimum Range	A range comprised of all levels of performance that are unfavorable in comparison to the Minimum Performance Level. The Service Provider will not earn points for performance in the Below Minimum Range.
Above Target Range	A range of performance that is considered to be in excess of Above Target Performance Threshold and is in excess of performance of the Target Range. The Service Provider shall be awarded a multiple of the Base Points for performance in the Above Target Range.
Improvement Metrics	
Minimum Performance Level	The Minimum Performance Level for Improvement Metrics is determined by a straight line between the Baseline Performance Level and Target Performance Level in Contract Year 10.
Performance Range Determination	Performance ranges for determination of Base Points earned shall be based on achieving performance improvement from the Baseline Performance Level to the Target Performance Level over a specified period of time (e.g., five years) ending in the "Target Year." The straight line between the Baseline Performance Level and the Target Performance Level achieved in the Target Year shall determine the performance levels necessary to earn 100% of the Base Points in each Contract Year.
Base Point Multipliers	The performance levels necessary to earn greater or lesser percentages, the "Base Point Multipliers," of Base Points in each Contract Year shall be established by the straight lines between the Baseline Performance Level and the Target Performance Level achieved in one year increments or decrements to the Target Year. For example, if the Target Year is 2018, the straight line between the Baseline Performance Level at 2013 and 2017 shall establish the performance levels to earn 125% of the Base Points in a given Contract Year.

Other Provisions	
Incentive Compensation	Commencing in Contract Year three , the annual Incentive Compensation for a Performance Category for any Contract Year shall be reduced by (i) 50% if the Service Provider has failed to achieve the Minimum Performance Level for the same Performance Metric in that Performance Category in the then-current Contract Year and any one of the two preceding Contract Years, or (ii) 100% if the Service Provider has failed to achieve the Minimum Performance Level for two or more of the same Performance Metrics in that Performance Category in the then-current Contract Year and any one of the two preceding Contract Years; provided, however, that, in each case such failure shall be excused to the extent of a Force Majeure event or LIPA Fault, but only to the extent that such event prevents or delays the Service Provider's achievement of such metric. Further, for the purposes of this adjustment, the Performance Metrics in the Customer Satisfaction Category - JD Power Customer Satisfaction Survey (Residential and Business), After Call Survey (Residential and Business) and Personal Contact Survey - will operate as a single performance metric, the "Customer Survey Performance Metric". Failure of the Customer Survey Performance Metric is defined as the Service Provider achieving less than 60% of the total points assigned to the Customer Survey Performance Metric.
Penalties	Notwithstanding the provisions above for determination of adjustments to Incentive Compensation, commencing in Contract Year three, failure of the Service Provider to (i) earn at least 60% of the total points assigned to the Customer Survey Performance Metric, or (ii) meet the Minimum Performance Level for SAIDI, in either case in the then-current Contract Year and any one of the two preceding Contract Years, shall result in (a) forfeiture of 100% of Incentive Compensation for the Contract Year, and (b) payment to LIPA of a penalty of 5% of the fixed component of the Management Services Fee; provided, however, that, in each case such failure shall be excused to the extent of a Force Majeure event or LIPA Fault, but only to the extent that such event prevents or delays the Service Provider's achievement of such metric.

Source: DR 4, Appendix 9

In accordance with the A&R OSA, "an amount of (i) $5.44 million, annually, for each of the 2014 and 2015 Contract Years and (ii) $8.7 million, annually, for each Contract Year thereafter, in each case expressed in 2011 Dollars and prorated as appropriate for a partial Contract Year, shall comprise the "Incentive Compensation Pool" to be earned based on favorable performance relative to the "Performance Metrics".[4] **Exhibit XIII-3** provides invoiced and actual incentive compensation levels. Pursuant to the LIPA Reform Act, the Department of Public Service (DPS) recommends incentive amounts based on its review of PSEG LI's report of its performance against the metrics in the OSA, relevant supporting data and information provided by PSEG LI, and LIPA's evaluation of the data, information and reports.

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[4] DR 20 Attachment 3

Exhibit XIII- 3
Incentive Compensation
(Dollars in Millions)

Year	Invoice Amount	DPS Recommendation	Amount Paid	Explanation of Difference
2014	$5.768	$5.480	$5.480	PSEG LI achieved 19 of 20 measures. PSEG LI failed to meet the OSHA Recordable Incidence Rate, but due to its interpretation of possible offsets, it invoiced the entire amount.
2015	$5.786	$5.208	$5.208	PSEG LI achieved 18 of the 21 performance metrics, but due to its interpretation of possible offsets invoiced the entire amount.
2016	$9.320	$9.233	$9.233	PSEG LI achieved 23 of the 25 performance metrics, but due to its interpretation of possible offsets invoiced the entire amount.

Source: DR 20 Attachments and DR 20 Supplement, DPS Review; LIPA/PSEG LI Fact Verification.

Balanced Scorecard

PSEG LI tracks and reports to LIPA two categories of performance metrics: 1) metrics used to determine PSEG LI's annual incentive compensation award (commonly referred to as Tier 1 metrics); 2) other metrics are not part of the incentive compensation award, but are still subject to active performance management. These are referred to as Tier 2 metrics. Metrics may shift between tiers based on operational needs. Tier 2 metrics may be specific to, or reported at, the PSEG LI department-level (i.e., Customer Operations, Transmission and Distribution (T&D) Electric Operations, Business Operations).

On a monthly basis, PSEG LI provides LIPA with a Balanced Scorecard Report/Presentation which includes a summary of PSEG LI's performance and supporting details for the Tier 1 Metrics. The Presentation also includes an Appendix of Tier 2 Metric Scorecards.[5] PSEG LI's Business Performance Excellence Team prepares the Balanced Scorecard with data from all areas of the business.[6] The Balanced Scorecard report aligns the Tier 1 metrics with the four elements of PSEG's corporate vision – "Being a recognized leader for: People providing Safe, reliable Economic and Greener Energy."[7]

Metrics evolve over time based on business needs. **Exhibit XIII-4** provides the metrics used in 2017, the associated tier, and the organizations to which they apply. Some metrics are reported at the corporate level and by each Department; others may be Department-specific. The column labeled PSEG LI indicates what metrics are reported at the corporate-level.

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[5] See The September 2017 Presentation as an example (DR 935 Attachment 1)

[6] DR 5

[7] DR 40

Exhibit XIII-4
PSEG LI Metrics - 2017

Metric	Tier	PSEG LI (Company-Wide)	Department		
			Customer Operations	T&D Electric Operations	Business Services
People					
OSHA Recordable Incidence Rate	Tier 1	✓	✓	✓	✓
OSHA Days Away Rate (Severity	Tier 1	✓	✓	✓	✓
Staffing Levels Permanent	Tier 2	✓	✓	✓	✓
Availability – Illness	Tier 2	✓	✓	✓	✓
Diversity Availability in Applicant Pool	Tier 2	✓			✓
Motor Vehicle Accident Rate	Tier 2		✓	✓	✓
Community Partnership Plan	Tier 2		✓	✓	✓
Safe, Reliable					
JD Power Residential Survey	Tier 1	✓	✓	✓	✓
JD Power Business Survey	Tier 1	✓	✓	✓	✓
After Call Survey Residential	Tier 1	✓	✓		
After Call Survey Business	Tier 1	✓	✓		
Personal Contact Survey	Tier 1	✓	✓	✓	
Average Speed of Answer (ASA)	Tier 1	✓	✓		
Abandonment Rate	Tier 1	✓	✓		
SAIFI	Tier 1	✓		✓	
CAIDI	Tier 1	✓		✓	
SAIDI	Tier 1	✓		✓	
Interconnection Cycle Time	Tier 1	✓	✓	✓	
Percent Advanced Metering Infrastructure (AMI) Measured Energy	Tier 1	✓	✓		
Long Term Estimates	Tier 1	✓	✓		
Purchased Power Invoicing	Tier 1	✓			✓
Customer Complaint Rate	Tier 1	✓	✓		
Internal Controls Test Failure Rate	Tier 2	✓	✓	✓	✓
Timely Remediation of Internal Control Test Failures	Tier 2	✓	✓	✓	✓
Momentary Average Interruption Frequency Index (MAIFI)	Tier 2			✓	
Capital Project Performance (Capital)	Tier 2	✓		✓	
Capital Project Performance (Federal Emergency Management Agency (FEMA))	Tier 2			✓	
Actual Meter Read Rate	Tier 2		✓		
Billing Exception Cycle Time	Tier 2		✓		
Customer Service Response Index	Tier 2		✓		
Regulatory Complaints	Tier 2		✓	✓	
Forced Automatic Outage Rate (Transmission)	Tier 2			✓	
Electric Damages per 1,000 Locates	Tier 2			✓	
Estimated Time of Restoration (ETR) Accuracy	Tier 2			✓	
National Energy Regulatory Commission (NERC) Circuit Improvement Program (CIP) Project Performance	Tier 2			✓	

Metric	Tier	PSEG LI (Company-Wide)	Department		
			Customer Operations	T&D Electric Operations	Business Services
T&D Preventive Maintenance	Tier 2			✓	
New Business Cycle Time	Tier 2			✓	
Restoration Preparedness	Tier 2			✓	
Social Media Followers	Tier 2				✓
Fuel & Purchase Power Cost Adjustment (FPPCA) Data Submittal	Tier 2				✓
New York Independent System Operator (NYISO) Capacity Compliance Filing	Tier 2				✓
Supplier Diversity	Tier 2				✓
Information Technology (IT) Critical Systems – Unplanned Outages	Tier 2				✓
IT Project Delivery - Cost	Tier 2				✓
IT Project Delivery - Schedule	Tier 2				✓
IT Project Delivery – Quality (Defects/$M)	Tier 2				✓
Percent of Financial Management Reports Delivered to LIPA	Tier 2				✓
Days to Distribute Variance Reporting	Tier 2				✓
Client Service Request - Incident on Time Completion Rate	Tier 2				✓
Security Vulnerability Inspections	Tier 2				✓
First Call Resolution	Tier 2		✓		
Interconnection Cycle Time (>50kW)	Tier 2			✓	
Economic					
Operating Budget ($M)	Tier 1	✓	✓	✓	✓
Capital Budget ($M)	Tier 1	✓	✓	✓	✓
Days Sales Outstanding (DSO)	Tier 1	✓	✓		
New Write-Off per $100 Billed Revenue	Tier 1	✓	✓		
Damage Costs	Tier 2	✓			
Accounts Receivable > 90 Days	Tier 2		✓		
Construction Work in Progress	Tier 2		✓		✓
Operations and maintenance (O&M) for Outside Services and Materials	Tier 2				✓
Green					
Customer Self Service	Tier 1	✓	✓		
EE Annualized Energy Savings	Tier 1	✓	✓		
Renewable Energy Generated	Tier 1	✓	✓		
EE and Renewable Cost / kWh	Tier 2		✓		
Paperless Billing (%)	Tier 2		✓		

Source: DR 6 Attachments.

B. EVALUATIVE CRITERIA

- Does LIPA/PSEG LI have appropriate processes for providing performance feedback (e.g., reliability and productivity) relating to its corporate mission, objectives and goals so LIPA can improve processes, redirect resources, and change priorities? Further discussion of LIPA's corporate mission is in **Chapter III - Executive Management and Governance**.)

- Does the Board of Trustees get involved in the performance feedback loop at the right time and to the right extent, and are its role and responsibilities appropriate?
- Is management held accountable for performance improvements, e.g., cost savings and productivity gains anticipated from specific capital and O&M programs and projects, and specific corporate goals? See **Chapter IX - Program and Project Planning and Management**.
- Do LIPA and PSEG LI make appropriate use of goals, key performance indicators and metrics?
- Does PSEG LI use benchmarking techniques to identify and develop performance targets?
- Does PSEG LI have effective change management and continuous improvement processes?
- Are there impediments that tend to constrain performance improvements and has LIPA and/or PSEG LI taken appropriate actions to remove impediments to performance improvements?
- Does PSEG LI employ effective processes for ensuring the accuracy of the data used in the calculation of performance results?
- Are baseline, target and minimum performance targets, metric definitions, and data sources consistent with the A&R OSA requirements?
- Are metric calculations accurate and consistent with the A&R OSA requirements?
- Have any modifications to the A&R OSA metrics, performance targets or categories and tiers been reasonable? Are adjustments between categories (improvement and maintenance) or Tiers warranted?
- Is the process for setting targets and developing new measures to truly drive improved performance sufficiently robust?

C. FINDINGS AND CONCLUSIONS

1. At the corporate level LIPA/PSEG LI have appropriate processes for providing performance feedback relating to their corporate missions, objectives and goals, as defined in the A&R OSA, so that PSEG LI can improve processes, redirect resources, and change priorities.

- PSEG LI's performance is substantially driven by the 20 to 25 Tier 1 incentive metrics (the number of metric changes over the years as metrics are added and deleted). These metrics are aligned with both PSEG LI's and LIPA's missions, which are shown in **Exhibit XIII-5**. By the nature of their contractual relationship, LIPA's and PSEG LI's missions are directly related; improving processes to achieve PSEG LI's goals also serves to achieve LIPA's goals.

Exhibit XIII-5
LIPA and PSEG Missions

LIPA	PSEG LI
Mission/Vision	**Mission**
LIPA is a not-for-profit public utility with a mission to enable clean, reliable, and affordable electric service for our customers on Long Island and the Rockaways.	At PSEG Long Island, our mission is to build an industry leading electric service company that places safety first, in all we do, providing our customers across Long Island and the Rockaways with: - Excellent customer service - Best in class electric reliability and storm response - Opportunities for energy efficiency and renewables - Local, caring, and committed employees, dedicated to giving back to their communities
	Vision
	Being a recognized leader for: - People providing - Safe, reliable - Economic and - Greener Energy

Source: DR 40, www.lipower.org/profile/mission.html.

  - **Cost containment** is a threshold metric which is consistent with both missions. Other affordability metrics include Days Sales Outstanding (DSO), net write-offs, and timely meter reading and billing (which affects both revenues and write-offs).
  - **Safety** is addressed through two metrics related to employee injuries.
  - **Reliability** is addressed through the industry standard SAIDI, SAIFI and CAIDI metrics.
  - **Cleaner green energy** is addressed in the Energy Efficiency and Renewable Load Reduction metric and web transactions/customer self-service.
  - **Customer satisfaction** supports PSEG LI's mission to provide excellent customer service, and LIPA's prior customer service challenges.

- The Balanced Scorecard Presentations provide monthly and year-to-date performance against the established metrics. The presentations address each metric in detail, and provides drill-downs and more detailed information on the results, reasons for any performance deviations and a discussion of initiatives to address any deviations.[8] In addition to the Tier 1 incentive metrics, the scorecards provide information on Tier 2 metrics.

- Tier 1 incentive metrics have been added or removed to address areas of concern, or instances where performance goals have been met. **Exhibit XIII-6** outlines the changes to the OSA incentive metrics. These changes were generally appropriate.[9]

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[8] DR 0018 and Attachments

[9] DR 0018 Attachments, DR 0006 (2017)

Exhibit XIII-6
OSA Incentive Metric Changes and Comments

2015	2016	2017
• Web Transactions Completed became Customer Self Service • Purchased Power Invoicing was added (Maintenance) [Note 1]	• Timely Billing became Billing Exception Cycle Time • After Call Surveys – Residential and Business and the Personal Contact Survey changed from Improvement to Maintenance Metrics (results improved to the levels typically seen of transactional surveys) • Customer Complaint Rate was added (Maintenance) • Interconnection Cycle Time was added (Improvement) • Long Term Estimates was added (Improvement) • EE and Renewable Achieved Load Reduction was split into two metrics and changed from Improvement to Maintenance • Actual meter read rate was dropped	• Billing Exception Cycle Time dropped (performance issues were resolved)

Note 1: While not a typical utility incentive metric, purchased power invoicing was added when PSEG LI took over that function to address specific concerns about the invoice review process. According to LIPA, the invoices often reflect complex, contractual and/or monetarily significant matters and the attention received as a Tier 1 metric has helped ensure a high level of accuracy and timeliness.
Note 2: Electric Damages per 1,000 locates had been an A&R OSA tracking metric in 2014 and was eliminated.
Source: DR 18 Attachments, DR 25 Attachment, September 2017 Balanced Scorecard presentation (DR 935), IR 32, LIPA/PSEG LI Fact Verification.

- LIPA and PSEG LI hold a monthly Balanced Scorecard Meeting to discuss PSEG LI's metric results. NorthStar attended two of the Balanced Scored Meetings.[10]
    - In addition to the discussion of the monthly scorecard results, PSEG LI updates LIPA on other activities. As an example, at the October 26, 2017 meeting, PSEG LI provided an update on a recent Major Accounts Customer Symposium, the results of the recent JD Power residential survey, a demo on the new proactive outage alerts program, PSEG LI's performance during the October 24-25 storm and an update on the reliability programs.[11]
    - To facilitate meeting effectiveness and efficiency, in late 2017, LIPA began to receive the scorecard package in advance and provide PSEG LI with a list of specific questions and additional information requests. PSEG LI will either respond in writing or at the meeting.
    - NorthStar reviewed the questions asked, and determined that the questions are good and demonstrate LIPA's monitoring of PSEG LI.[12]

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[10] IR 133 and 215
[11] IR 215, DR 934
[12] DR 936, DR 410

  - In-meeting discussions of PSEG LI's metric results were meaningful.[13] Unfortunately, the meeting time is limited, as the meetings are only scheduled for three hours.

2. **The Tier 1 metrics are largely focused on customer satisfaction.**

- In the 2014 scorecard, 47.6 percent of the eligible base points were classified as customer service measures. Two additional metrics that were classified as Cost Management, actual meter read rate and timely billing, are frequently classified as customer service.[14] Inclusion of these metrics as customer service would increase the relative weighting to 57 percent.

- Customer service represented 45.4 percent of the eligible base points in 2015, 41.7 percent in 2016, 43.5 percent in 2017, and 37.8 percent in 2018.[15] The A&R OSA specifies that the customer satisfaction category be allocated 40 percent.[16]

- The customer service metrics were all initially classified as improvement metrics which meant PSEG LI was able to earn a multiplier of up to 150 percent of the base points.

3. **The Tier 1 metrics have been consistently achieved. LIPA and PSEG LI should continue to evaluate how to best incent service provider performance, drive continuous improvement and align the metrics with the focus of LIPA and PSEG LI's long-term strategy and operational needs.**

- Since the beginning, PSEG LI has significantly exceeded many of the metric targets, as shown in **Exhibit XIII-7**.

Exhibit XIII-7
PSEG LI Actual Performance - 2014 to 2016

Metric	Type	2014	2015	2016
Operating Budget	Threshold	Met	Met	Met
Capital Budget	Threshold	Met	Met	Met
People				
OSHA Recordable Incidence Rate	Improvement	Missed	Missed	150%
OSHA Days Away Rate (Severity)	Improvement	100%	Missed	150%
Safe, Reliable				
JD Power Residential Survey	Improvement	150%	125%	125%
JD Power Business Survey	Improvement	150%	150%	150%
After Call Survey Residential	Improvement	150%	150%	Points Earned
After Call Survey Business	Improvement	150%	150%	Points Earned

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[13] IR 133 and 215, DR 410 Attachments

[14] These were classified as Financial Performance in the A&R OSA, which is reasonable.

[15] DR 25 Attachment and LIPA/PSEG LI Fact Verification.

[16] DR 4 Attachment

Metric	Type	2014	2015	2016
Personal Contact Survey	Improvement	150%	150%	Points Earned
Average Speed of Answer	Improvement	150%	150%	150%
Abandonment Rate	Improvement	150%	150%	150%
SAIFI	Maintenance	Upper Boundary	Upper Boundary	Missed
CAIDI	Maintenance	Upper Boundary	Upper Boundary	Points Earned
SAIDI	Maintenance	Upper Boundary	Upper Boundary	Missed
Actual Meter Read Rate	Improvement	150%	Missed	
Timely Billing/Billing Exception Cycle Time	Improvement	150%	150%	150%
Interconnection Cycle Time	Improvement			125%
Percent AMI Measured Energy	Improvement			150%
Long Term Estimates	Improvement			150%
Purchased Power Invoicing	Improvement		125%	
Customer Complaint Rate	Maintenance			Points Earned
Economic				
Days Sales Outstanding	Improvement	150%	150%	125%
New Write-Off per $100 Billed Revenue	Maintenance	Upper Boundary	Upper Boundary	Points Earned
Green				
EE and Renewable Achieved Load Reduction	Improvement	125%	125%	
Customer Self Service	Improvement		125%	150%
EE Annualized Energy Savings	Maintenance			100%
Renewable Energy Generated	Maintenance			150%

Source: DR 20 Attachments 2 and 6.

- As a result of the unique service provider relationship and relative performance levels under the prior arrangement, the LIPA performance management process differs from that of a traditional IOU.
  - Initial A&R OSA targets were generally established to achieve improved performance levels within five years.
  - Under the terms of the A&R OSA, both parties must agree to revisions to the metrics.[17] Any revisions to the metrics, targets, weightings or tiers is the result of a negotiated process.
  - Some of the Tier 1 metrics used by LIPA/PSEG LI may not be typically used to determine incentive compensation for the executives, management or employees of an IOU, but are used by LIPA/PSEG LI to address prior performance issues or motivate the service provider. These same metrics may be tracked by IOUs and have performance targets, but are not used for incentive compensation purposes.
- Adjusting a performance metric is a multi-step process. According to the Contract Administration Manual (CAM) Procedure BPE-F1:[18]

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[17] DR 4 A&R OSA Appendix 9, pp. 7-8

[18] DR 41 CAM-BPE-F1 Performance Metric Definition and Adjustment Process

  - Either PSEG LI or LIPA, or both, may recognize a need to amend or adjust one or more performance metrics regardless of tier assignment. Potential causes include evolving business conditions, force majeure, LIPA fault, other reasonably unanticipated events or additional LIPA regulatory needs.
  - PSEG LI forms working groups to collect data and analyze the impacts. Recommendations are reviewed internally and then by the PSEG LI management team to identify an optimal solution.
  - A proposal is presented to LIPA subject matter experts.
  - PSEG LI and LIPA review and finalize the metrics or changes based on mutual agreement. LIPA/PSEG LI also solicit input from DPS.
  - LIPA submits the proposal to the Management Review Board (MRB). The MRB discusses the proposal internally and with the PSEG LI/LIPA teams. The MRB determines whether to accept or reject the LIPA proposal.
  - If the proposal is rejected by the MRB, the PSEG LI Management Team must determine whether to accept the decision and forego discussed modifications or to formally dispute the proposal, in accordance with the dispute resolution process laid out in Section 8.6 of the A&R OSA.

- There is no required timeframe for determination of the metrics and targets, and there was no formal sign-off until the 2017 metric negotiation process.[19] Metrics should ideally be finalized before the beginning of the new measurement cycle, and no later than the first quarter of the new cycle.

  - 2016 metrics were presented to the BOT Contract Oversight Committee on March 21, 2016. The final OSA Metrics and Targets Book was not finalized until mid-2016.[20]
  - Discussion of 2017 metrics began in September 2016.[21] Revisions to the JD Power targets were still being considered when half the survey results had been reported.[22] The 2017 metrics were presented to the BOT Oversight Committee on March 29, 2017. The targets were officially finalized and signed off on, on August 16, 2017.[23]

- **Exhibit XIII-8** shows target and actual performance for the OSA incentive metrics from 2014 to 2016, and NorthStar's notes on the metrics.

Exhibit XIII-8
OSA Incentive Metrics – Target and Actual Performance

Metric		2014	2015	2016	NorthStar Notes
OSHA Recordable Incidence Rate	Target	1.67	2.11	2.31	Previous National Grid reporting used to determine the baseline did not include meter reading or field collections. Per OSHA, should not be used for employee incentives, as it may serve to promote under-reporting.
	Actual	2.80	2.33	1.47	
OSHA Days Away Rate (Severity)	Target	29.81	35.55	39.43	
	Actual	29.16	61.11	26.02	

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[19] IR 124

[20] IR 124, LIPA/PSEG LI Fact Verification

[21] DR 700 September 16, 2016 LIPA Draft proposal

[22] DR 700 Attachment

[23] IR 32 and LIPA/PSEG LI Fact Verification

Metric		2014	2015	2016	NorthStar Notes
JD Power Customer Satisfaction (Residential)	Target	542	565	588	Utilities commonly use relative ranking. LIPA/PSEG LI added a relative ranking component in 2017.
	Actual	571	584	610	
JD Power Customer Satisfaction (Business)	Target	551	576	602	
	Actual	595	631	689	
After Call Survey (Residential)	Target	67.0%	71.5%	83.3%	Shift to a maintenance metric was appropriate. See following exhibit.
	Actual	87.4%	91.6%	92.9%	
After Call Survey (Business)	Target	47.6%	71.5%	83.3%	
	Actual	81.6%	90.6%	92.4%	
Personal Contact Survey	Target	83.7%	85.5%	87.3%	
	Actual	90.7%	92.9%	94.6%	
Average Speed of Answer	Target	79	66	53	Performance consistently exceeds standards. Should be a maintenance metric. With performance in the first quartile, LIPA expects ASA to formally move to a maintenance metric in 2019.
	Actual	54	35	24	
Abandonment Rate (AR)	Target	3.8%	3.4%	3.0%	Could be a Tier 2 metric. Utilities typically measure but do not use as an incentive metric, focusing instead on service levels or ASA and first call resolution (FCR). Per LIPA, AR was moved to Tier 2 in 2018. FCR was initiated as a Tier 2 tracking metric in 2017 and may eventually become a Tier 1 metric.
	Actual	2.6%	1.4%	1.1%	
SAIDI	Target	66.2	68.5	68.5	Changed targets based on a study regarding the effect of the implementation of a new outage management system on reliability statistics. See Chapter VIII for additional discussion.
	Actual	59.1	65.7	75.5	
SAIFI	Target	0.90	0.92	0.92	
	Actual	0.72	0.84	1.11	
CAIDI	Target	84	85	85	
	Actual	82	79	68	
Interconnection Cycle Time	Target			85%	Supportive of REV and clean energy initiatives.
	Actual			98%	
% AMI Measured Energy	Target			13.6%	Added to track installation of AMI.
	Actual			17.0%	
Actual Meter Read Rate	Target	96.8%	97.1%		Appropriately dropped to Tier 2.
	Actual	97.1%	91.9%		
Long Term Estimates	Target			2,747	Added to reduce the number of accounts with three consecutive missed cycle reads.
	Actual			2,411	
Timely Billing/Billing Exception Cycle Time	Target	61.5%	66.1%	70.7%	Could have been dropped to Tier 2 earlier as issue was largely resolved due to process changes minimizing the number of "exceptions" pushed from the call center to the billing group when PSEG LI took over.
	Actual	88.4%	90.2%	93.5%	
Purchased Power Invoicing	Target		90.0%	90.0%	See Exhibit XIII-6, Note 1.
	Actual		98.3%	99.3%	
Customer Complaint Rate	Target			11.3	This information is tracked by the DPS and comparative information is posted on the DPS website creating an incentive to keep complaints at a minimum. The metrics already have a heavy customer focus and other metrics (JD Power and the customer survey) would highlight complaint issues.
	Actual			5.7	
Days Sales Outstanding (DSO)	Target	41.9	40.3	38.8	Fairly commonly used industry metric.
	Actual	37.6	36.8	37.0	
Net Write-Offs per $100 Billed Revenue	Target	0.69	0.69	0.69	Fairly commonly used industry metric.
	Actual	0.66	0.67	0.57	

Metric		2014	2015	2016	NorthStar Notes
Web Trans. Completed/ Customer Self Service	Target	5%	20%	30%	Metric Change in 2015. All utilities have an incentive to drive customers to less expensive channels. Could be moved to a Tier 2 metric.
	Actual	10.6%	31.3%	82.0%	
EE/RE Achieved Load Reduction	Target	60.3	69.98		Energy Efficiency and Renewable Energy were split.
	Actual	69.5	83.27		
EE Achieved Load Reduction	Target			55.03	
	Actual			57.74	
RE Achieved Load Reduction	Target			22.00	
	Actual			29.07	

Source: DR 0018, NorthStar Analysis, and LIPA/PSEG LI Fact Verification.

- **Exhibit XIII-9** provides a discussion of PSEG LI's rationale for changes to the Tier 1 incentive metrics targets.

Exhibit XIII-9
Target Adjustments

Metric	Effective Date of Change	Change
After Call Survey – Residential	2015	Target level of performance was adjusted due to better than expected performance in 2014. Rather than converting the metric to maintenance at this time, PSEG LI and LIPA agreed to accelerate the target.
After Call Survey - Business	2015	
After Call Survey – Residential	2016	Metric changed from Improvement to Maintenance. Target adjusted accordingly.
After Call Survey - Business	2016	
Personal Contact Survey	2016	Metric changed from Improvement to Maintenance. Target adjusted accordingly.
SAIDI	2015	Changed from 66.2 to 68.5 based on a study regarding the effect of the implementation of a new outage management system on reliability statistics.
SAIFI	2015	Changed from 0.90 to 0.92 based on a study regarding the effect of the implementation of a new outage management system on reliability statistics.
CAIDI	2015	Changed from 84 to 85 based on a study regarding the effect of the implementation of a new outage management system on reliability statistics.
OSHA Recordable Incidence Rate	2015	Target changed from 1.67 to 2.11. Previous National Grid reporting used to determine the baseline did not include meter reading or field collections.
OSHA Days Away Rate	2015	Target changed from 29.81 to 35.55. Previous National Grid reporting used to determine the baseline did not include meter reading or field collections.
OSHA Recordable Incidence Rate	2016	Target changed from 2.11 to 2.31. Resets baseline solely based on PSEG LI performance in 2014 and 2015, to achieve first quartile performance by year 10. Previous National Grid reporting used to determine the baseline did not include meter reading or field collections.
OSHA Days Away Rate	2016	Target changed from 35.55 to 39.43. Resets baseline solely based on PSEG LI performance in 2014 and 2015, to achieve first quartile performance by year 10. Previous National Grid reporting used to determine the baseline did not include meter reading or field collections.
Days Sales Outstanding	2016	Changed to reflect the impact of the revenue decoupling mechanism and a LIPA review of the calculation.

Source: DR 25 Attachment, DR 18 and Attachments, DR 24 Attachments, DR 85 Confidential Attachment 2015 - PA - 2015 Revenue Reporting Review.pdf, LIPA/PSEG LI Fact Verification.

- As part of the annual process, LIPA proposes changes to the metrics. The principles outlined in LIPA's 2017 metric proposal are appropriate and consistent with good practice.[24]

  - Metrics should be measurable and actionable
  - Metrics should be tied to one or more aspects of LIPA's mission
  - Baseline data should exist
  - PSEG LI should have control over outcomes
  - Target should drive improvement.

- PSEG LI may provide its own proposal and discussions ensue to develop the final agreed upon metrics for the year.[25]

- The final 2017 metrics included the following:[26]

  - Modifications to the targets for JD Powers to reflect a combination of score and rank. Both surveys continued to be an improvement metric.
  - Customer Complaint Rate response was not replaced with CSRI.
  - ASA and Abandonment Rate remained as incentive metrics.
  - SAIDI, SAIFI and CAIDI targets were adjusted based on an external study. MAIFI was not added as an incentive metric.
  - Measurement methodology for energy efficiency and renewable load reductions was changed.
  - Long-Term Estimates (LTE) and AMI targets were reset.
  - Billing Exception Cycle time was dropped to Tier 2

4. Tier 2 metrics have changed over time as intended.

- As initially designed, Tier 2 metrics were to be used to test metrics or to continue monitoring metrics that no longer warranted high-level executive management attention. Some provide reasonable, consistent tracking of key items tied to the missions of PSEG LI and LIPA. Others are tied to the specific functions of an individual department. In other cases, they are used to address items for which LIPA has concerns.

- **Exhibit XIII-10** shows the creation and elimination of metrics over time, and the shift between tiers. Tier 2 metrics are discussed in detail in other chapters of this report.

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[24] DR 700 Attachment 8 September 16, 2016 LIPA Draft proposal and DR 700 Attachment 7 LIPA Proposed 2017 metrics

[25] DR 700 and Attachments

[26] DR 700 Attachment 6 August 16, 2017 letter

Exhibit XIII-10
Metrics 2014 – 2017
(Tier 1 Incentive Metrics are shown in Grey, Tier 2 Metrics in Orange)

Metric	2014	2015	2016	2017
People				
OSHA Recordable Incidence Rate	Tier 1			
OSHA Days Away Rate (Severity	Tier 1			
Staffing Levels Permanent	Tier 2			
Availability – Illness	Tier 2			
Diversity Availability in Applicant Pool		Tier 2		
Motor Vehicle Accident Rate	Tracking	Tier 2		
Community Partnership Plan		Tier 2		
Employee Development	Tier 2			
Succession Bench Strength	Tier 2			
Veteran External Hiring Rate	Tier 2			
Completion of Continuous Improvement Plans		Tier 2		
Safe, Reliable				
JD Power Residential Survey	Tier 1			
JD Power Business Survey	Tier 1			
JD Power Communications Index		Tier 2 w/ targets	No Targets	
JD Power Corporate Citizenship Index		Tier 2 w/ targets	No Targets	
After Call Survey Residential	Tier 1			
After Call Survey Business	Tier 1			
Personal Contact Survey	Tier 1			
Average Speed of Answer	Tier 1			
Abandonment Rate	Tier 1			
SAIFI	Tier 1			
CAIDI	Tier 1			
SAIDI	Tier 1			
MAIFI	Tier 2 Tracking			
SAIFI (excl. sec/singles)			Tier 2	
CAIDI (excl. sec/singles)			Tier 2	
SAIDI (excl. sec/singles)			Tier 2	
Interconnection Cycle Time			Tier 1	
Interconnection Cycle Time (>50kW)				Tracking
Percent AMI Measured Energy			Tier 1	
Long Term Estimates		Tier 2	Tier 1	
Purchased Power Invoicing		Tier 1		
Customer Complaint Rate			Tier 1	
Capital Project Performance		Tier 2		
Net Metering		Tier 2		
Capital Project Performance (Capital)		Tier 2		
Capital Project Performance (FEMA)		Tier 2		
Internal Controls Test Failure Rate	Tier 2 Tracking	Tier 2		
Timely Remediation of Internal Control Test Failures	Tier 2 Tracking	Tier 2		
Internal Controls Walkthroughs & Testing		Tier 2		
Actual Meter Read Rate	Tier 1		Tier 2	

Metric	2014	2015	2016	2017
Timely Billing	Tier 1			
Billing Exception Cycle Time		Tier 1		Tier 2
First Call Resolution	Tier 2 Tracking	Tracking		Tier 2 Tracking
Customer Service Response Index		Tier 2 TBD		
Regulatory Inquiries – Non-Collections	Tier 2 Tracking	Tracking		
Regulatory Collection Rate	Tier 2 Tracking	Tracking		
Regulatory Complaints			Tier 2 Tracking	No Targets
Forced Automatic Outage Rate (Transmission)	Tier 2			
Electric Damages per 1,000 Locates	Tier 2 Tracking			
Police & Fire Response Rate	Tier 2 Tracking			
Estimated Time of Restoration (ETR) Accuracy	Tier 2			
NERC CIP Project Performance			Tier 2	
T&D Preventive Maintenance	Tier 2			
Mandatory NERC Training	Tier 2			
Vegetation Management	Tier 2			
Hazardous Waste Manifested	Tier 2			
Commitment to Health and Safety		Tier 2		
New Business Cycle Time		Tier 2 Tracking		
Storm Preparedness and Response/ Restoration Preparedness		Tier 2 Tracking		
Social Media Followers		Tier 2		
FPPCA Data Submittal		Tier 2		
NYISO Capacity Compliance Filing		Tier 2		
Supplier Diversity	Tier 2			
HR Time to Accept	Tier 2			
IT Critical Systems – Unplanned Outages	Tier 2 (2 metrics)	1 metric		
IT Project Delivery Performance	Tier 2			
IT Project Delivery – Cost		Tier 2		
IT Project Delivery – Schedule		Tier 2		
IT Project Delivery – Quality (Defects/$M)		Tier 2		
Percent of Financial Management Reports Delivered to LIPA		Tier 2		
Days to Close – Accounting	Tier 2			
Days to Distribute Variance Reporting	Tier 2		No Targets	
Client Service Request - Incident on Time Completion Rate		Tier 2	No Targets	
Security Vulnerability Inspections		Tier 2		
Economic				
Operating Budget ($M)	Tier 1			
Capital Budget ($M)	Tier 1			
Days Sales Outstanding	Tier 1			
New Write-Off per $100 Billed Revenue	Tier 1			
Damage Costs	Tier 2			
Forecast Liquidity Requirements	Tier 2			

Metric	2014	2015	2016	2017
	Tracking			
Procurement Savings	Tier 2			
AR > 90		Tier 2 Tracking		
Paperless Billing		Tier 2		
Construction Work in Progress		Tier 2 Tracking		
O&M for Outside Services and Materials		Tier 2		
Green				
Web Transactions Completed	Tier 1			
EE and Renewable Achieved Load Reduction	Tier 1			
EE Annualized Energy Savings			Tier 1	
Renewable Energy Generated			Tier 1	
Customer Self Service		Tier 1		
EE and Renewable Cost / kW	Tier 2			
Paperless Billing (%)			Tier 2	
Environmental Audit & Assessment Remediation Rate	Tier 2			

Source: DR 18 Attachments 1-3, DR 6.

5. PSEG LI uses benchmarking to develop performance targets. NorthStar did not verify the targets.

- The A&R OSA anticipated the use of benchmarking to establish targets: "As a general standard for metrics and where appropriate, the Target Performance Level will be First Quartile performance. Any benchmark source used to establish First Quartile values and any adjustments to a Target Performance Level must reflect local and regulatory considerations and will be subject to the Parties' approval."[27]

- LIPA and PSEG LI are working to provide transparency on the benchmarking data provided by third-parties, to facilitate LIPA's review.

- The JD Power Residential and Commercial survey metrics are based on the JD Power benchmarking survey. PSEG LI has detailed access to this data including the results of other utilities.[28] The JD Power Dashboard is used extensively to drill down and evaluate relative performance.

- **Exhibit XIII-11** provides a listing of the other Tier 1 targets tied to achieving first quartile performance based on benchmark data.

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[27] DR 4 A&R OSA Appendix 9

[28] IR 122. In this interview PSEG LI presented a demo of the JD Power Interactive Dashboard, including an overview of available data.

Exhibit XIII-11
Use of Benchmarking in OSA Metric Targets

Metric	Panel	Study
OSHA Recordable Incidence Rate and OSHA Days Away Rate	National Peer Panel's average three-year's results	PSE&G Peer Panel
Customer complaint rate	NYS Utilities	Reported to DPS by all NYS Utilities
Average Speed of Answer and Abandonment Rate	JD Power East Region: Large Segment Companies	AGA/EEI Customer Services Peer Panel Data, First Quartile Customer Services Peer Panel Data.
SAIDI, SAIFI and CAIDI	National Electric Reliability Peer Panel Companies	PSE&G Electric Peer Panel, First Quartile Electric Utility Peer Panel, NY DPS Electric Reliability Performance Report Data, Southern Company Distribution Peer Panel
Days Sales Outstanding	JD Power East Region: Large Segment Companies	AGA/EEI Customer Services benchmark studies
Net Write Offs per $100 Billed	JD Power East Region: Large Segment Companies	AGA/EEI Customer Services benchmark studies and First Quartile Customer Services Peer Panel data

Source: DR 25 Attachment.

- The PSEG LI customer service metrics are generally comparable to those of PSE&G in New Jersey. Ten of the metrics are common.[29] PSEG LI tries to conform to the PSE&G metric definition when possible.[30]

6. PSEG LI has effective continuous improvement processes; however, they are heavily focused on JD Power survey results.

- JD Power performs a perception survey of a variety of industries, including electric utilities. It is not a transactional survey which measures a customer's experience following contact with the utility. JD Power survey respondents may not have had any recent contact with the utility. Overall scores may go up or down over time, so most utilities evaluate their relative ranking (i.e. position within a quartile). As an example, in its July 2017 press release, JD Power announced that "overall residential electric utility customer satisfaction increases for sixth consecutive year."[31]
    - The Electric Utility Residential Customer Satisfaction Study measures customer satisfaction with electric utility companies by examining six factors: power quality and reliability; price; billing and payment; corporate citizenship; communications; and customer service. The most recent study is based on responses from 99,145 online interviews conducted from July 2016 through May 2017 among residential customers of the 138 largest electric utility brands across the United States, which collectively represent more than 98 million households.[32]

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[29] PSE&G also has gas operations. IR 32.
[30] IR 141 and 142
[31] http://www.jdpower.com/press-releases/jd-power-2017-electric-utility-residential-customer-satisfaction-study
[32] http://www.jdpower.com/press-releases/jd-power-2017-electric-utility-business-customer-satisfaction-study

  - The 2017 Electric Utility Business Customer Satisfaction Study measures satisfaction among business customers of 87 targeted U.S. electric utilities, each of which serves more than 40,000 business customers. In aggregate, these utilities provide electricity to more than 12 million customers. Overall satisfaction is examined across six factors (listed in order of importance): power quality and reliability; corporate citizenship; price; billing and payment; communications; and customer service. Satisfaction is calculated on a 1,000-point scale. The study is based on responses from more than 19,000 online interviews with business customers who spend at least $200 a month on electricity. The most recent study was fielded from February through June 2017 and July through October 2017 (referred to as waves).

- In 2014, PSEG LI launched its multi-year Customer One program designed to improve residential and business customer satisfaction. The Customer One Vision is to become a "top quartile" service provider to all residential and business customers by year-end 2018, by making substantial improvements in every facet of customer satisfaction, every year.[33]

  - Customer One is governed by a Steering Committee of VPs, directors and managers who vet initiatives and provide on-going direction, oversight and support for implementation of selected projects.
  - The committee is organized into six JD Power Project Teams – one for each area of the customer experience: Power Quality & Reliability, Price, Billing & Payment, Communications, Corporate Citizenship, and Customer Services.
  - Each project team is comprised of an Executive Vice President (EVP), a director level lead, a core project team, and other cross functional support.
  - Teams meet on an ongoing basis to develop and implement initiatives. The Steering Committee meets on a monthly basis to review the latest research and intelligence, progress of initiatives and provide additional budgetary, personnel, and logistic support.
  - The teams have developed numerous initiatives to improve performance. Each team provides a quarterly progress update to the Steering Committee.

- In 2014, PSEG LI implemented a Lean Six Sigma Program. Twenty-nine Lean Six Sigma Black Belt and 16 Lean Six Sigma Green Belt Candidates have been trained. PSEG LI conducts Process Identification, Process Improvement and DMAIC (Define, Measure, Analyze, Improve, and Control) Teams. PSEG LI currently has several Process Identification projects in progress and 14 DMAIC projects in various stages of the DMAIC improvement process.[34]

- **Exhibit XIII-12** provides a listing of continuous improvement initiatives designed to address operating efficiencies.

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[33] DR 312

[34] DR 85

Exhibit XII-12
PSEG LI Continuous Improvement Initiatives – Operating Efficiencies

Team	Focus
FEMA / Operations Process Flow Team	Process identification and improvement to FEMA / Operations process to better capture and document storm work in the field to justify FEMA reimbursement
Investment Recovery Team	Process identification and improvement to recover funds for scrap
Materials Management Process Team	Process identification and improvement to ensure the effectiveness and efficiency of the Materials Management Process
Non-Product Billing Teams (e.g. Property Damage)	Process identification and improvement for multiple Non-Product Billing cost recovery streams to ensure accurate information for billing and maximum cost recovery.
Power Asset Management Team	Process identification of the Power Markets processes for understanding and improved management.
PSEG-LI Safety Council Team	Process identification of the Safety Council structure and operation for improved safety results.
OSHA / OSHA Days Away Rate Incident Analysis Team	Review of current and best practice identification to reduce OHSA incidents.
Motor Vehicle Accident Rate Team	Review of current and best practice identification to reduce Motor Vehicle incidents
Incident Analysis & Investigation Team	Review of current and best practices to log, communicate, investigate and remediate OSHA and First Aid incidents.
Outage Restoration Process Improvement Team	Process identification and improvement of the Outage Restoration process
Substation Team	Process identification and efficiency / effectiveness improvement
Vegetation Management	Process identification and improvement for Vegetation Management focusing on efficiency and effectiveness
Set Up for Work	Develop and implement process(es) to setup circuits for work to ensure safety. Determine the number and type of resources needed effectively accomplish setting up the circuits properly and efficiently.

Source: LIPA/PSEG LI Fact Verification.

7. The LIPA Board of Trustees (BOT) receives updates on LIPA/PSEG LI's performance as appropriate; LIPA staff has been tasked with managing PSEG LI's performance by the BOT.

- The full Board routinely receives the monthly PSEG LI Balanced Scorecard which provides performance against the A&R OSA metrics. It also receives the annual metrics.

- To assess financial performance, the full Board receives the annual budget. The Finance & Audit Committee of the Board receives the annual budget, audited financial results, and results of the Enterprise Risk Management program. It receives quarterly swap reports and investment reports, monthly financial results and results on hedging and Internal Audit activities as appropriate.[35] The Governance Committee receives a monthly Litigation Report and annual goals. The Oversight and Personnel Committees receive the annual Oversight Committee report and the Staffing Report, respectively.[36]

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[35] DR 13 Attachments

[36] DR 13 Attachments

- As part of its APPA-recommended governance process, the Board receives annual reports on progress against the various Board policies. These policies may be specific to LIPA or may include information on PSEG LI's performance relative to the A&R OSA metrics.[37] The Board receives the Operations and Oversight Plan on an annual basis. See **Chapter III - Executive Management and Governance** for further discussion.

- The LIPA Staff is responsible for the day-to-day oversight of PSEG LI.

8. LIPA reviews the reported A&R OSA metrics to ensure their appropriateness and accuracy.

- LIPA retained an external auditor to perform a review of the initial OSA metrics. The report was released in April 2014. The scope of the review included the following:[38]

  - Attend weekly A&R OSA metrics updates given by PSEG LI.
  - Review the peer panels for comparability to LIPA's operations, i.e. revenues, number of customers.
  - Trace detailed data used in developing LIPA baseline metrics provided by National Grid and trace detailed data used by PSEG LI in developing quartile measurements by metric to supporting documentation.
  - Document PSEG LI's process for data collection and review PSEG LI's Tableau data tool used to report metrics.
  - Review the business rules and test the mathematical calculation of each metric against the requirements of the A&R OSA.
  - Create process flowcharts for each OSA metric including a description of the process and an example of the calculation.

- LIPA retained a safety expert to review the 2014 reported safety metric results and data collection methodology.[39]

- In 2015, LIPA retained an external consultant to verify the revenue and accounts receivable information used by PSEG LI to calculate Days Sales Outstanding. LIPA had noticed conflicting monthly revenue and accounts receivable data on different reports coming out of the Customer Accounting System (CAS).[40] This resulted in a modification to the metric calculation.

- In 2015, an external auditor reviewed the meter reading, timely billing and web transaction processes.[41]

- In 2016, LIPA engaged another firm to audit three new OSA metrics: Interconnection Cycle Time, Long Term Estimates and AMI Measured Energy. The firm verified PSEG LI's performance in the month of June 2016. It also reviewed the processes and controls,

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[37] DR 6
[38] DR 86
[39] DR 86
[40] DR 86
[41] DR 86

created process maps, and verified whether the metric calculations were accurate and the inputs reconciled to supporting documentation.[42]

- With each monthly Balanced Scorecard report, LIPA receives a standard suite of supporting data files and asks for additional information if needed.[43] It also performs periodic audits to evaluate the reported results.[44]

- On a monthly basis LIPA reviews the reported results with PSEG LI and provides feedback and questions to PSEG LI.[45]

9. **PSEG LI has a well-established process for performance metric calculation. PSEG LI has demonstrated adequate procedures for data acquisition, data transfer and calculation methodology.**

- To calculate its metric results, PSEG LI uses data from both enterprise-wide systems and in-house developed databases. **Exhibit XIII-13** provides the data sources for the 25 A&R OSA incentive metrics.

- PSEG LI calculates performance results monthly for most metrics. One metric, Long Term Estimates, is reported annually. Each month, data is transferred from the responsible organization shown in **Exhibit XIII-13** to the Performance Analysis and Reporting Organization. NorthStar found no instances where a metric was not calculated for a specific month.[46]

- PSEG LI has an established schedule for developing the monthly results. Data is transferred on the 10th of each month. The Performance Analysis and Reporting Organization evaluates the information for the next two weeks. The Balanced Scorecard report is prepared and distributed at month's end.[47]

- The Performance Analysis and Reporting Organization has established templates for receipt of the data. The templates are Excel spreadsheets. Calculations of the metrics are formulary and included in the template, providing consistency from month-to-month.[48]

Exhibit XIII-13
Data Sources

Metric	Responsible Organization	Data Source/System
OSHA Recordable Incident Rate	T&D Services	Safety Information Management System (SIMS) and SAP
OSHA Days Away Rate	T&D Services	SIMS and SAP

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[42] November 30, 2016 Performance Metrics Review (DR 86 Attachment)
[43] IR 142
[44] DR 86
[45] IR 133 and 215
[46] DR 411
[47] IR 142
[48] DR 600

Metric	Responsible Organization	Data Source/System
JD Power Customer Satisfaction Survey - Residential	Customer Intelligence	JD Power Website
JD Power Customer Satisfaction Survey - Business	Customer Intelligence	JD Power Website
After Call Survey – Residential	Customer Intelligence	NUANCE (3rd party data capturing and reporting system)
After Call Survey - Business	Customer Intelligence	NUANCE
Personal Contact Survey	Customer Intelligence	ISA (3rd party data capturing and reporting system)
Average Speed of Answer	Customer Contact & Billing	IVR Statistics, 21st Century Reports (3rd party mainframe reporting system), CISCO Reports (3rd party call center reporting system)
Abandonment Rate	Customer Contact & Billing	IVR Statistics, 21st Century Reports, CISCO Reports
SAIFI	Asset Management	CGI OMS
CAIDI	Asset Management	CGI OMS
SAIDI	Asset Management	CGI OMS
Interconnection Cycle Time	Planning, Resources & Engineering	Access Database
AMI Measured Energy	Meter Services	Customer Accounting System (CAS)
Long Term Estimates	Meter Service	CAS
Billing Exception Cycle Time	Customer Contact & Billing	Exception Memo Management System (EMMS) Database
Purchased Power Invoicing	Power Markets	Power Markets SharePoint and Individual Invoices
Customer Complaint Rate	Customer Relations	DPS
Operating Budget	PSEG LI Finance	SAP
Capital Budget	PSEG LI Finance	SAP
Days Sales Outstanding	Revenue Operations	CAS and PageCenter (3rd party mainframe reporting system)
Net Write Offs per $100 Billed Rev	Revenue Operations	CAS and PageCenter
Customer Self-Service	Customer Experience	EnergySavvy Report (3rd party Customer Experience Software)
EE Achieved Load Reduction	Energy Efficiency	LM Captures (Lockheed Martin Software application)
RE Achieved Load Reduction	Energy Efficiency	LM Captures

Source: DR 745.

- Performance Analysis and Reporting performs a reasonableness review of the data and reported metrics. Metric owners are responsible for explaining variances.[49]

10. NorthStar's review of selected metrics identified some incorrect calculations. However, none of the miscalculations resulted in PSEG LI mistakenly reporting whether a target was achieved or not.

- NorthStar tested a sample of performance metrics as shown in **Exhibit XIII-14** for accuracy and validity of source data.

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[49] IR 32

- NorthStar's result from the metric testing are shown in **Exhibit XIII-15**. NorthStar identified the following issues:
    - The interconnection cycle time metric was established in March 2016. NorthStar found minor discrepancies between the PSEG LI reported result and NorthStar's independent calculation. In total, the discrepancy involved 8 transactions out of 5,920 transactions. It was determined that:
        - Four of the transactions were not included in the metric because the application date preceded the metric.
        - One transaction was excluded for administrative reasons – the meter was installed prior to the application.
        - The three remaining transactions were incorrect due to data entry errors.[50]
    - There are five categories of billing exceptions included in the Billing Exception Cycle Time: Demand, High/Low, MRP1, MRP2 and Regular. NorthStar tested the number of high/low billing exceptions reported for the first ten months of 2016. NorthStar found an error in March 2016. PSEG LI reported in its metric 3,327 observations and NorthStar found 3,251. There is no material difference in the performance metric calculation, as there is a difference of 76 observations out of a total of 27,803 observations.

Exhibit XIII-14
Performance Metrics Selected for Testing by NorthStar

Metric	Calculation	Time Period	Source Data Test
OSHA Recordable Incident Rate	Reported Incidences x 200,000 Number of Hours Worked	December 2016 and Annual	Used source data to calculate metric and sampled individual transactions
After Call Survey - Residential	Number of Positive Responses Total questions	March 2016	Used source data to calculate metric
Average Speed of Answer	Time on Hold of Answered Calls Number of Calls	March 2016, December 2016 and Annual	Used template downloaded from IVR
SAIFI	Number of Customers Interrupted Number of Customers	All months all years	Used data from OMS
CAIDI	Customer Minutes of Interruption Number of Customers	All months all years	Used data from OMS
Interconnection Cycle Time	Number of On Time Activities Number of Applications	October 2016	Used access databased and sampled individual transactions
Long Term Estimates	Count of number of Long Term Estimates	2016	Used CAS data and calculated independently

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[50] DR 600, 814 and 815 and IR 176

Metric	Calculation	Time Period	Source Data Test
Billing Exception Cycle Time	Number of Exceptions Completed On time Number of Completed Exceptions	March 2016 and October 2016	Used EMMS data and calculated independently – verified number of hi/lo counts
Customer Complaint Rate	Number of Complaints x 100,000 Number of Customers	December 2016 and Annual	Verified DPS data on DPS website and independently calculated metric
Capital Budget	Dollars Spent Budget	March 2016 and Annual	Used Finance & Accounting Flash Reports and independently calculated metric

Source: DR 18, 113 and 600.

Exhibit XIII-15
Results of NorthStar's Performance Metric Testing

Metric	Target	Reported	NorthStar Calculation
After Call Survey – Residential			
March 2016	Greater than 82.8%	92.8%	92.8%
Average Speed of Answer			
March 2016	Less than 53 sec	6 seconds	6.47 seconds
December 2016	Less than 53 sec	13 seconds	12.9 seconds
Year 2016	Less than 53 Sec	24 seconds	23.57 seconds
SAIFI	See Chapter VIII	See Chapter VIII	See Chapter VIII
CAIDI	See Chapter VIII	See Chapter VIII	See Chapter VIII
Interconnection Cycle Time			
October 2016	Greater than 85% within 10 days for each step	99%	99.43%
Long Term Estimates	Less than 2,747	2,411	2,411
Year 2016			
Billing Exception Cycle Time			
March 2016	Greater than 67.3%	84.6%	84.9%
December 2016	Greater than 70.7%	98.7%	98.7%
Customer Complaint Rate			
December 2016	Less than 11.3	3.6	3.62
Year 2016	Less than 11.3	5.7	5.72
Capital Budget			
March 2016	$ 23.5	$ 35.4 M	$ 35.4 M
Year 2016	$457.8 to $466.9	$ 384.7 M	$ 384.7 M

Sources: DR 18, 222, 280, 411, 562, 600, 814, 815, 820; IR 176 and 177 and, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/448C499468E952C085257687006F3A82?OpenDocument

11. NorthStar selected a sample of Tier 2 metrics for testing and found most of them to be calculated correctly.

- NorthStar selected a sample of Tier 2 metrics for testing as shown in **Exhibits XIII-16 and XIII-17.**

Exhibit XIII-16
Line of Business Performance Metrics Selected

Selected Metric	Responsible Organization	Data Source/System
Capital Project Performance	Project Controls	SAP and Primavera P6
Damage Costs	Business Assurance and Resilience	Claims information
Internal Control Test Failure Rate	Internal Audit	Internal Audit File
AR>90	Revenue Operations	CAS
Customer Service Response Index	Customer Relations	DPS Report
ETR Accuracy	Emergency Planning	Outage Management System (OMS)
Capital Project Performance (FEMA)	Project Control	SAP and Primavera P6

Source: DR 745.

Exhibit XIII-17
Performance Metric Testing

Metric	Calculation	Time Period	Source Data Test
Capital Project Performance	Weighted average of FEMA and PSEG LI: includes milestone achieved and capital spend	October 2016 Year 2016	Used source data and calculated independently
Damage Costs	Dollars paid in damages	October 2016	Used source data and calculated independently
Internal Control Test Failure Rate	Number of audit tests failed/total planned tests	October 2016 Annual 2016	Used source data and calculated independently
AR>90	Amount of dollars with accounts receivable greater than 90 days/outstanding dollars	October 2016 Year 2016	CAS worksheet
Customer Service Response Index	As reported on DPS website[51]	October 2016 Year 2016	DPS
ETR Accuracy	Percent of Estimated Time of Response within 2 hours of estimate	October 2016	Used source data and calculated independently
Capital Project Performance (FEMA)	Weighted average of FEMA includes milestones achieved and capital spend	October 2016 Annual 2016	Used source data and calculated independently

Source: DRs 411 and 600 and
http://www3.dps.ny.gov/W/PSCWeb.nsf/All/448C499468E952C085257687006F3A82?OpenDocument

- The results of NorthStar's metric testing are shown in **Exhibit XIII-18**. NorthStar has identified issues as follows:

  - Capital Project Performance's calculation is inaccurate. It is determined by a weighted average of PSEG LI capital projects and FEMA capital projects. PSEG LI is weighted at 72 percent and FEMA is weighted at 28 percent. Both PSEG LI and FEMA performance is evaluated based on a 50/50 contribution of milestones achieved on time and percent of forecast capital spent.
    - The FEMA milestone calculation shows 42 out of 42 milestones achieved for October 2016. The source data shows 41.83 milestones achieved. There is an error in the data as there are no decimals in a count.[52]

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[51] http://www3.dps.ny.gov/W/PSCWeb.nsf/All/448C499468E952C085257687006F3A82?OpenDocument

    - The PSEG LI milestone shows 50 out of 68 milestones achieved for October 2016. Source data shows 48 out of 66 milestones achieved. NorthStar believes the in-service dates are double counted.[53]
    - The PSEG LI actual to forecast spend does not match the data provided, resulting in cascaded errors.[54]
    - As a result, the combined FEMA and PSEG LI metric reported is incorrect. PSEG LI reports missing the metric while in fact they achieved it.[55]
- The Internal Controls Test Failure Rate is calculated correctly; however, the source data, Master Audit Sheet, does not match the template used to calculate the metric. There are differences by month for the number of tests performed. The annual total matches.[56]
- NorthStar found a number of discrepancies in the ETR Accuracy Calculation.
    - It is not unusual to see minor differences in the number of ETRs. One main cause is how the data is parsed and split by month.[57]
    - The major difference is in 57 observations (28 in November and 29 in December) that PSEG LI did not believe fulfilled the restoration with two hours of estimate requirement. These 57 observations were exactly 2 hours.[58]
    - The language of the Performance Metric is unclear as to whether these observations should or should not be included.[59]
    - **Exhibit XIII-19** summarizes the differences.

Exhibit XIII-18
Performance Metric Testing Results

Metric	Target	Reported	NorthStar Calculation
Capital Project Performance			
October 2016	Greater than 74.7%	73.9%	80.6%
Year 2016	Greater than 74.7%	71.6%	86.1%
Damage Costs October 2016	Less than $3 million annually ($250k per month)	$ 32 k	$ 32.3 k
Internal Control Test Failure Rate			
October 2016	Less than 9%	0%	0%
Year 2016	Less than 9%	4.5%	4.5%
AR>90			
October 2016	Less than 19.3%	14%	14%
Customer Service Response Index			
October 2016	Greater than 9.3	9.9	9.9
Year 2016	Greater than 9.3	9.6	9.6

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[52] DR 875 Attachment 1
[53] DR 870
[54] DR 873 and 874
[55] DRs 870-876
[56] DRs 18 Attachments 1-3, 600 Attachments 50 and 51, and 880 Attachment 1
[57] DR 950
[58] DR 950
[59] DR 411

Metric	Target	Reported	NorthStar Calculation
ETR Accuracy			
November 2016	Greater than 75%	55%	56%
December 2016	Greater than 75%	59%	61%
Capital Project Performance FEMA			
October 2016	Greater than 80.5%	99%	99%
Year 2016	Greater than 80.5%	89.3%	89.2%

Source: DR 411, 600, and 870 through 875.

Exhibit XIII-19
ETR Accuracy Discrepancies

	Total ETRs	ETRs On time	Percent
November 2016			
PSEG LI	1,582	863	55%
NorthStar	1,582	865 + 28= 893	56%
December 2016			
PSEG LI	1,314	779	59%
NorthStar	1,307	773 + 29 = 802	61%

Source: DR 411 and 950.

D. RECOMMENDATIONS

1. Develop and adhere to a schedule for completion of the annual metric identification and target setting process that provides for a final list of approved metrics at the beginning of the measurement year. Tier 1 Metrics, definitions, weightings and targets should be set no later than February 28. There should be a final sign-off on all of the aforementioned elements. Note: This is not intended to imply that the metric book must be completed by February 28; however, it should be done in an expeditious manner.

2. PSEG LI and LIPA should streamline its process to facilitate the establishment and measurement of meaningful operational metrics to monitor performance, incorporating DPS staff input, and potentially bifurcating the Tier 2 metrics. This might expedite the finalization of the Tier 1 metrics. Examples include:

   - Establish a smaller group of Tier 2 metrics used to test metrics for possible inclusion as a Tier 1 metric or to continue to monitor performance when a Tier 1 metric has been moved to a Tier 2 metric.

   - Establish a separate classification of metrics to be used to monitor performance in specific areas or for operational reporting. These metrics would not be tied to compensation and could then be used to address such items as the following:

     - Changes in regulatory requirements or NYS initiatives (e.g., Reforming the Energy Vision, Clean Energy)
     - Elements of LIPA's Strategic Plan, Utility 2.0 or the IRP.

- AMI implementation status
- Issues identified by internal or external audits, including performance deficiencies identified by NorthStar's audit.
- Operational changes or revised priorities.
- Tracking new initiatives or sub-elements of existing initiatives.
- Metrics intended to address efficiency and effectiveness.
- As examples, a number of the Tier 2 metrics used over time would more appropriately have been part of this category: social media followers, staffing levels permanent, percent of financial management reports delivered to LIPA.

3. LIPA and PSEG LI should continue to evaluate how to best incentivize service provider performance (Tier 1 metrics), drive continuous improvement and align the metrics with the focus of LIPA and PSEG LI's long-term strategy/operational needs and industry best practices.

4. Define the metric calculation methodology to specify whether service restorations completed in exactly two hours should be included in the ETR Accuracy performance metric. NorthStar found the specified calculation methodology open to some interpretation. Currently, PSEG LI does not include restoration times of exactly two hours. This should be reconciled between PSEG LI and LIPA.

XIV. FUEL AND PURCHASED POWER

This chapter examines LIPA and PSEG LI's fuel and power supply activities. Specific areas addressed include: participation in regional power markets and reliability entities; oversight of power supply and fuel supply contracts; long term power supply planning and procurement; power supply and fuel hedging; and fuel and purchased power cost recovery through the Power Supply Cost tariff.

A. BACKGROUND

To meet its load requirements, LIPA purchases on-island and off-island power supplies. LIPA does not own generation facilities other than its 18 percent interest in the Nine Mile Point 2 (NMP2) nuclear power plant. The majority of LIPA's annual capacity obligations, and some of its energy needs are linked to the following long-term contracts:

- Amended and Restated Power Supply Agreement (A&R PSA) — Provides for the sale to LIPA by National Grid Generation (NG Generation) of all of the capacity and, to the extent LIPA requests, energy from the former Long Island Lighting Company (LILCO) oil and gas-fired generating plants on Long Island (the PSA units).

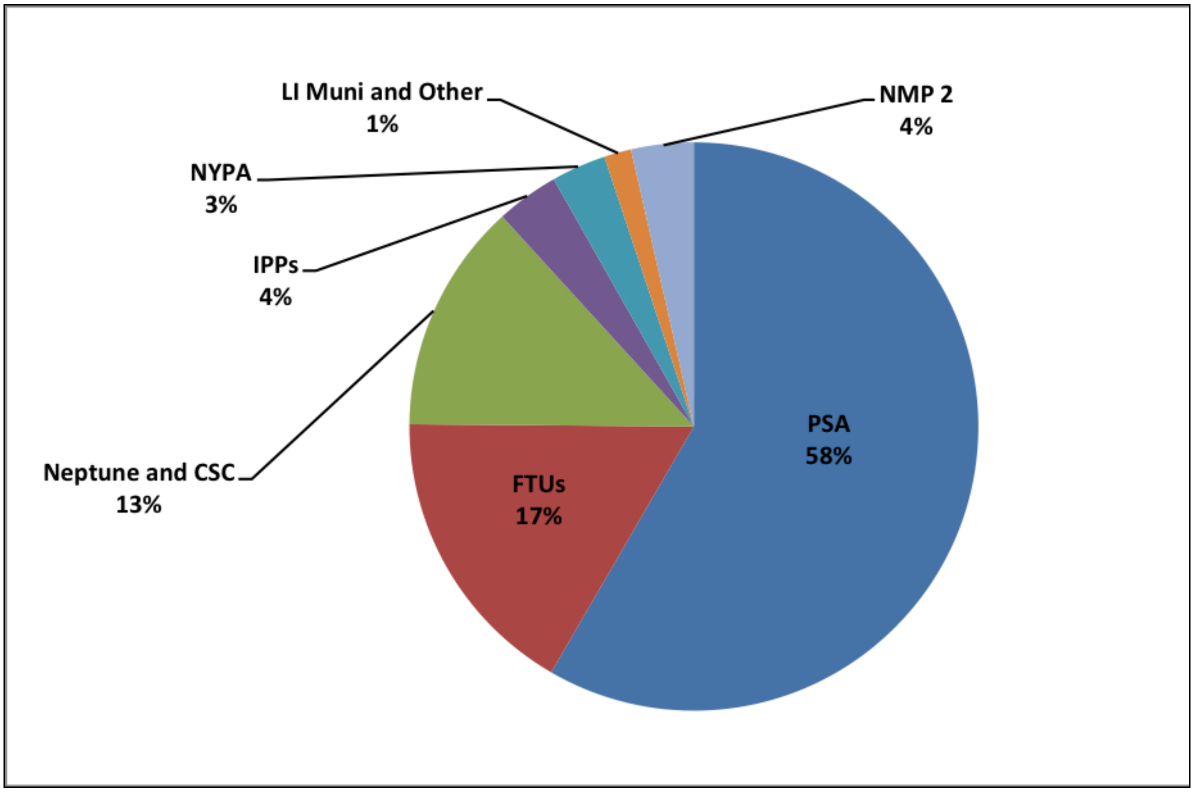
- Neptune Regional Transmission System — A 660 MW High Voltage Direct Current (HVDC) submarine cable to New Jersey. The Neptune cable began commercial operation in the summer of 2007.

- 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. A 100 MW pumped storage facility, Bear Swamp is linked to the CSC contract. The CSC began commercial operation in 2002.

- Fast Track Units (FTU) – On-island power plants built under contract to LIPA by several developers in the early 2000s.

A breakdown of LIPA's projected capacity and energy resources for 2017 is shown in **Exhibit XIV-1** and **Exhibit XIV-2**. The PSA units provide 58 percent of LIPA's capacity requirements. As further discussed in Conclusion 13 of this chapter, LIPA's capacity planning is based on the Long Island transmission district (Zone K) requirements which includes the Long Island municipalities (Freeport, Greenport, and Rockville Center) and load served by the New York Power Authority that is physically located on Long Island.

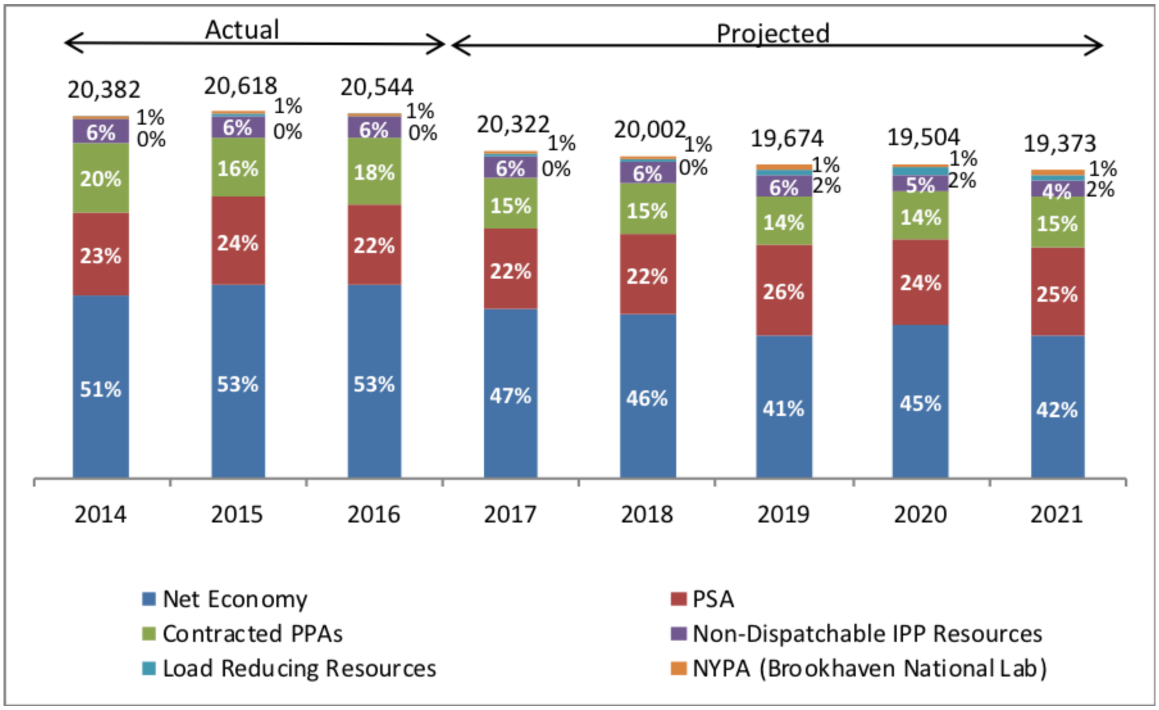
Exhibit XIV-1
Long Island Projected On and Off-Island Capacity Resources – 2017 (6,318 MW)



Source: DR 341 Attachment 1.

Exhibit XIV-2 shows the actual and projected energy breakdown by source for LIPA for the period 2014 through 2021. In 2017, LIPA expected to obtain 47 percent of its energy through spot purchases, 22 percent from the A&R PSA, 22 percent from other Purchased Power Agreements (PPAs), and 9 percent from NMP2. Aside from several "small" must take energy only contracts, LIPA's energy requirements are satisfied by the economic dispatch of the generating units under contract to LIPA and the purchase and sale of electric energy in regional power markets.

Exhibit XIV-2
LIPA Energy Resources 2014 to 2021 (GWh)



Source: DR 341 Attachment 1.

Although the overall percentage contribution remains low, LIPA projects a significant increase in load reducing resources in 2019, from the current 89 GWh (less than one percent) to 389 GWh (approximately two percent). Load reducing resources include the Eastern Long Island Solar Project (ELISP), Feed-In-Tariffs (FIT), fuel cells, and emergency generators.[1]

Regional Power Markets

As a participant in the Northeast wholesale energy markets, LIPA must comply with the rules and standards put forth by the New York Independent System Operator (NYISO), ISO New England (ISO-NE) and PJM Interconnection (PJM). LIPA must also comply with the rules of reliability entities such as NYS Reliability Council (NYSRC); Northeast Power Coordinating Council (NPCC); and the North American Electric Reliability Corporation (NERC).

- **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 NYISO Board of Directors.

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[1] DR 341

- **ISO-NE** - 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.

- **PJM** - an RTO 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.

- **NYSRC -** promotes and preserves the reliability of electric service on the NYS 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 NYS Power System. The NYSRC is governed by the NYSRC Executive Committee comprised of transmission owners (including LIPA) and other interested parties.

- **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.

- **NPCC** - one of eight reliability regions which report to NERC. It 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.

LIPA is a participating member in a number of market and reliability organizations in NYS, including the NYISO, NYSRC, and NPCC, as well as NERC and the out-of-state RTOs where LIPA has contract interests (PJM and ISO-NE). Under the terms of the Amended and Restated Operating Service Agreement (A&R OSA), as contract manager and agent for LIPA, PSEG LI provides coverage and support on relevant committees and working groups.[2]

Power Supply Management and Fuel Management Services

Effective January 1, 2015, PSEG Energy Resources & Trade LLC (PSEG ER&T) assumed responsibility for day-to-day power supply management (PSM) and fuel management (FM) services pursuant to the Fuel Management Agreement (FMA) and Power Supply Management Agreement (PSMA) included as Appendices 7-1 and 7-2 to the A&R OSA. Prior to 2015, these services were provided by Con Edison Energy, Inc. (CEE).

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[2] DR 150

Section 4.2(A)(6)(c) of the A&R OSA gave PSEG LI the right, exercisable within 10 business days of the effective date of the A&R OSA, for PSEG LI or its affiliates to provide power supply management and fuel supply management services commencing January 1, 2015. PSEG LI exercised that right.

PSEG Energy Resources & Trade LCC's (PSEG ER&T) PSM services include:

- Day-ahead load forecasting
- Bidding of capacity, energy and ancillary services into respective ISO electricity markets
- Estimating fuel usage
- Scheduling of power transactions across cables interconnecting LIPA's service area to PJM and ISO-NE
- 24/7 real-time operations support to receive calls and/or emails from generator operators, Electric Systems Operations, NYISO, ISO-NE, PJM. Make necessary bidding changes as events are triggered in real time.

PSEG ER&T's FM services include the management of all aspects of the fuel supply for LIPA's generating facilities (PSA and PPA facilities), including:

- Determining the type of fuel (gas or oil) used and the fuel supply sources
- Forecasting natural gas prices
- Nominating, scheduling, and coordinating the movement and use of fuels to operate generating facilities
- Managing the inventory, replenishment and quality of oil at dual-fuel capable generation units on Long Island in order to ensure performance when operating conditions do not accommodate local transportation of natural gas.

PSEG ER&T also executes LIPA's power supply and fuel hedging program.

Amended and Restated Power Supply Agreement

Under the A&R PSA, originally signed in 1998, NG Generation 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.[3] The original PSA expired on May 27, 2013; the current A&R PSA began on May 28, 2013, and ends April 30, 2028. The A&R 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 dispatch and for bidding those units into the NYISO capacity and energy markets. Under terms of the A&R PSA, the PSA units only run when requested by LIPA. While LIPA is not obligated to purchase energy or ancillary services under the A&R PSA, LIPA is required to purchase the PSA unit capacity.[4]

The units covered by the A&R PSA are shown in **Exhibit XIV-3**.

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[3] DR 4 Attachment PSA A&R

[4] FERC ORDER ACCEPTING AND SUSPENDING PROPOSED TARIFF SHEETS, AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES, Issued March 31, 2010, Docket ER10-705-000

Exhibit XIV-3
PSA Units

PSA Units:	Capacity (MW)	Facility Type	Fuel
Northport 1, 2, 3, 4	1,552	ST	Gas, Residual Oil
Holtsville 1-10	524	CT	Distillate Oil
E.F. Barrett 1, 2	385	ST	Gas, Residual Oil
Port Jefferson 3, 4	383	ST	Gas, Residual Oil
E.F. Barrett 1-6 and 8-12 E.F, Barrett 7 [Note 1]	305	CT	Gas, Distillate
Wading River 1-3	241	CT	Distillate Oil
Glenwood 4-5 [Note 1]	239	ST	Gas
Glenwood 1-3	115	CT	Distillate Oil
Far Rockaway 4 [Note 1]	111	ST	Gas
Shoreham 1, 2	64	CT	Distillate Oil
West Babylon 4	49	CT	Distillate Oil
East Hampton 1	18	CT	Distillate Oil
Northport Gas Turbine 1	13	CT	Distillate Oil
Port Jefferson Gas Turbine	12	CT	Distillate Oil
Southhold 1	12	CT	Distillate Oil
Southampton 1	7	CT	Distillate Oil
East Hampton 2-4	6	IC	Distillate Oil
Montauk 1-3 [Note 1]	6	IC	Distillate Oil

Note 1: Unit(s) retired.
Source: DR 4, PSM Agreement, LIPA/PSEG LI Fact Verification.

LIPA's PSA costs include the following:

- **Monthly Capacity Charge** – designed to recover the fixed costs of the generating facilities including return on investment and depreciation, insurance costs, taxes, administrative costs, and fixed operation and maintenance expenses.
- **Monthly Variable Charge** – designed to recover variable operation and maintenance costs, environmental fees, and labor costs, multiplied by the net MWh generated.
- **Monthly Capacity Adjustment Charge** – permits the recovery of non-variable expenses, net of insurance proceeds, associated with extraordinary items.
- **Monthly Regional Greenhouse Gas Initiative (RGGI)** charges.
- **Monthly Variable Adjustment Charge** – provides for the recovery of startup costs, base and peak load operation, and fuel swaps, as well as variable environmental compliance activities not recovered through the capacity charge or RGGI charge.
- **Monthly Ancillary Service Charge** – costs in providing ancillary services.[5]

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[5] DR 4 A&R PSA

Other Power Purchase Agreements

In addition to the A&R PSA, LIPA purchases approximately 2,100 MW of capacity under the long-term PPAs listed in **Exhibit XIV-4**.[6]

Exhibit XIV-4
Summary of Purchased Power Agreements (excluding the PSA)

Plant	Capacity (MW)	Contract Start	Contract End	Primary Fuel Type
On-Island (LIPA has Fuel Responsibility)				
National Grid - Glenwood Landing	79	Jun-02	Jun-27	Nat Gas
National Grid - Port Jefferson	80	Jul-02	Jul-27	Nat Gas
J-Power USA - Shoreham	90	Aug-02	Oct-20	Oil
J-Power USA - Edgewood	92	Jul-02	Oct-18	Nat Gas
J-Power USA - EQUUS	48	Aug-04	Jun-17	Nat Gas
J-Power USA - Pinelawn	78	Oct-05	Oct-25	Nat Gas
NextEra (FPL) - Bayswater	54	Jun-02	Jun-20	Nat Gas
NextEra (FPL) - Jamaica Bay	54	Jul-03	Jul-18	Oil
Hawkeye - Greenport	52	Jul-03	Jul-18	Oil
Calpine - Bethpage Energy Center	77	Jul-05	Jul-25	Nat Gas
Caithness - Caithness I	264	Aug-09	Jul-29	Nat Gas
Off-Island				
Brookfield - Bear Swamp	96		Apr-21	Hydro
NextEra - Marcus Hook	685	Jun-10	Jun-30	N/A
Other				
Covanta - Hempstead Resource Recovery	72	Sep-12	Aug-22	Refuse
Covanta - Huntington Resource Recovery	24	Oct-12	Oct-22	Refuse
Covanta - Babylon Resource Recovery	14	Sep-12	Aug-22	Refuse
Town of Islip - Islip Resource Recovery	9	Sep-12	Aug-22	Refuse
Long Island Solar Farm LLC - Long Island Solar Farm	31	Nov-11	Oct-31	Solar
Village of Freeport - Freeport	10	Mar-04	Mar-34	Nat Gas
Various (2) - FIT-I	50	Various	Various	Solar
Various (3) - FIT-II	100	Various	Various	Solar
Various (4) - Non-Solar	20	Various	Various	Various

Source: DR 342 Attachment 1, LIPA/PSEG LI Fact Verification.

Integrated Resource Plan

LIPA’s current long-term resource development plan is documented in a draft Integrated Resource Plan (IRP) issued on April 10, 2017. The 2017 draft IRP updates LIPA’s Electric Resource Plan for the period 2010-2020 and examines the potential transmission and generation needs for long-term system reliability under a range of scenarios and in the context of economic and policy considerations, including: 1) meeting the newly enacted 50X30 Clean Energy Standard; and, 2) NYSRC and NYISO reliability criteria. LIPA has an oversight role in the IRP process.

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[6] Fuels Services Request for Proposal (RFP)

LIPA's Fuel and Purchased Power Cost Recovery

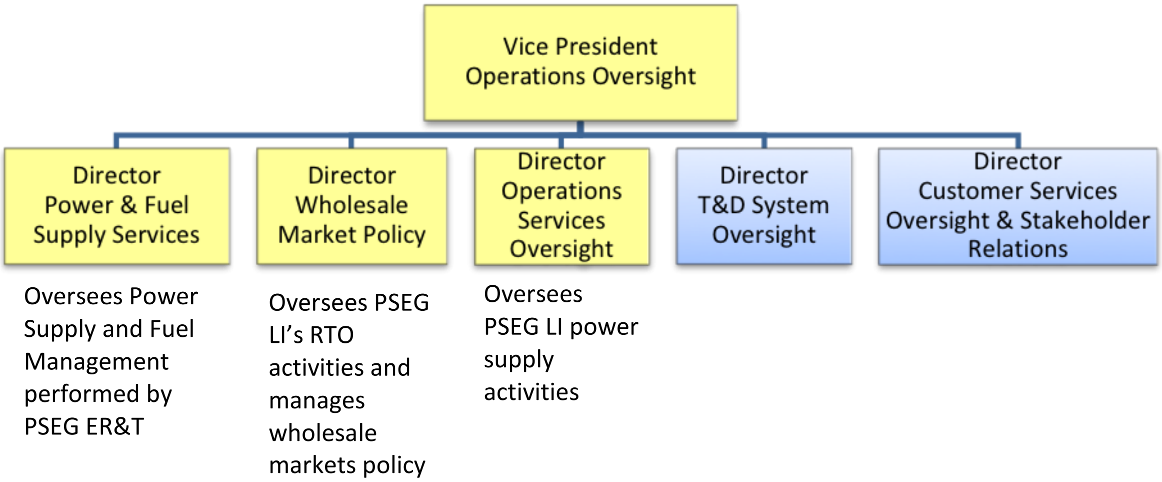
LIPA's Tariff for Electric Service (tariff) includes a Power Supply Charge (PSC), documented in Leaf 166, which applies to all service classifications. The PSC allows the monthly adjustment of rates due to changes in fuel and purchased power and other related costs set forth in the tariff. Until January 2017, this adjustment was referred to as the Fuel and Purchased Power Cost Adjustment (FPPCA) clause in the tariff, although it was referred to as the Power Supply Charge on customer bills.

PSC clauses have been adopted by numerous utilities, including the New York State (NYS) investor-owned utilities (IOUs). 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 tariff lists the categories of fuel and purchased power and related costs to be recovered in the PSC and describes the rate calculation methodology.

LIPA Oversight of Power and Fuel Supply Activities

Positions highlighted in yellow in **Exhibit XIV-5** are responsible for LIPA's oversight of PSEG LI's and PSEG ER&T's power and fuel supply activities.

Exhibit XIV-5
LIPA's Oversight Organization

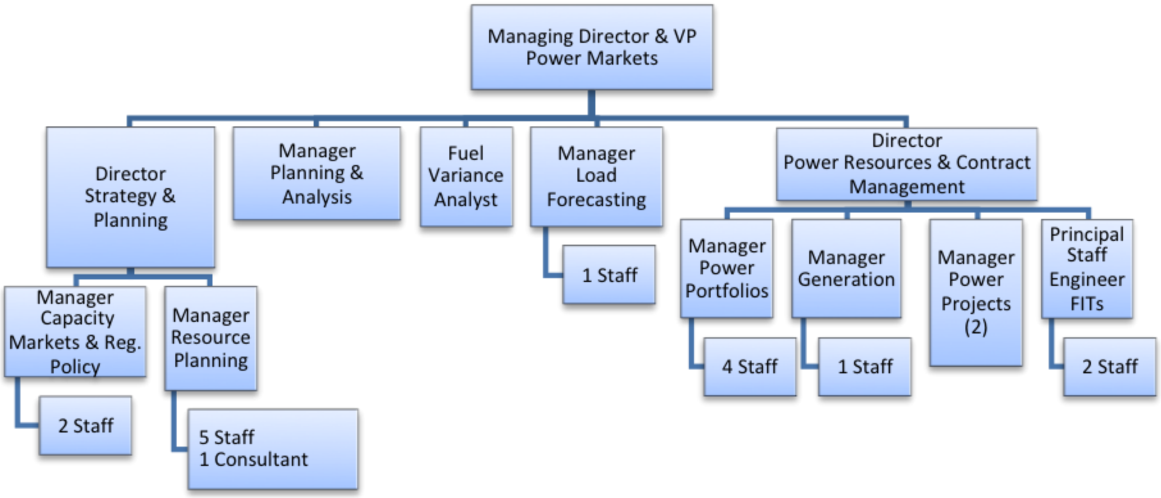


Source: DR 683.

PSEG LI Power Markets Organization

PSEG LI assumed responsibility for LIPA's power markets activities on January 1, 2015, in accordance with Section 4.2(A)(6)(c) of the A&R OSA, which states that LIPA will transfer the functions of its Power Supply group no later than December 31, 2014. The current PSEG LI Power Markets organization is shown in **Exhibit XIV-6**.

Exhibit XIV-6
PSEG LI Power Markets Organization



Source: DR 854 and 958.

Services provided to LIPA by PSEG LI Power Markets include:

- Long term power supply strategy and planning
- Contract management of all power purchase and firm transmission service agreements
- Monitoring of PPA generation performance data and Renewable Energy Credit (REC) allowances
- Procurement of capacity and energy through RFPs and FITs
- Management of FITs
- Regional power market monitoring and participation
- Determination of power supply costs
- Load forecasting
- Other special studies, such as the NYS-mandated repowering studies of the Barrett, Port Jefferson and Northport generating facilities.[7]

Chapter Organization

The following chapter sections examine four areas of LIPA's Fuel and Power Supply activities, as summarized in **Exhibit XIV-7**.

Exhibit XIV-7
Fuel and Power Supply Elements Reviewed

Chapter Section	Elements	Responsible Organizations/Positions
B. Regional Power Markets	▪ Participation in NYISO, PJM and ISO-NE	▪ LIPA Director, Wholesale Market Policy

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[7] DR 426 and 854

	▪ \Actions regarding NYSRC, NPCC, NERC, and FERC	▪ PSEG LI Power Markets' Capacity Markets & Regulatory Policy Group
C. Power Supply and Fuel Contracts	▪ Power Supply Agreement (NG Generation On-Island Plants)	▪ PSEG LI Power Markets' - Power Portfolios group - Generation group
	▪ Day-to-Day Power Supply ▪ Power Supply Management Agreement Fuel Supply Management Agreement	▪ LIPA Director, Power & Fuel Supply Services ▪ PSEG ER&T
D. PSEG LI's Supply Procurement	▪ Long Term Power Supply Planning ▪ Power Supply Portfolio ▪ Renewable Energy ▪ Power Supply RFPs and FITs	▪ PSEG LI Power Markets' - Capacity Markets & Regulatory Policy - Power Projects and FIT
	▪ Power Supply and Fuel Hedging	▪ LIPA Director, Power & Fuel Supply Services ▪ Enterprise Risk Management Committee
E. Fuel and Purchased Power Cost Recovery	▪ Recovery of cost through Power Supply Cost clause ▪ Calculation of PSC costs	▪ PSEG LI Power Markets' Planning & Analysis group

B. REGIONAL POWER MARKETS

Evaluative Criteria

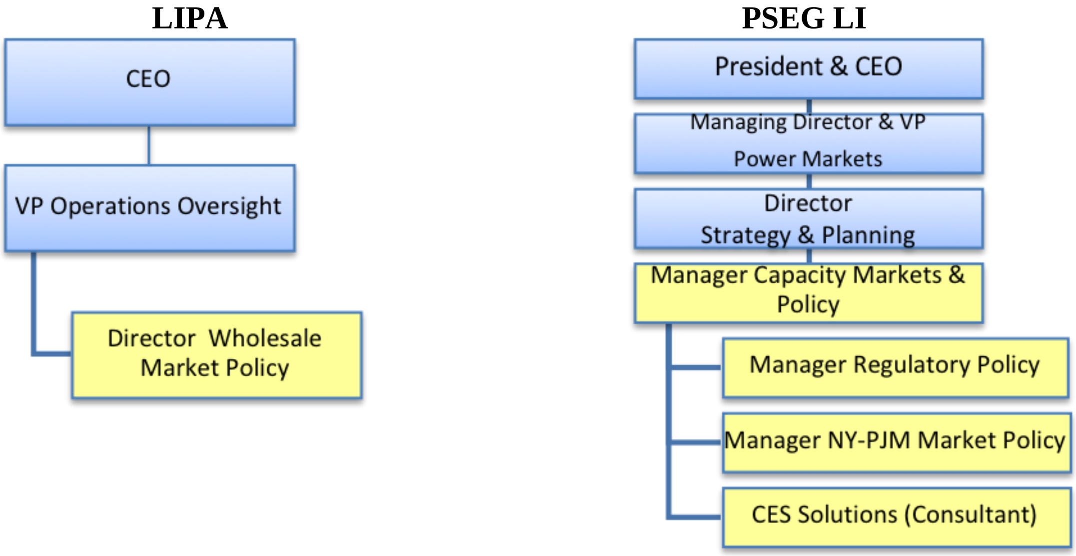
- Does LIPA/PSEG LI have appropriate coverage at stakeholder forums (e.g., standing committees, working groups and task forces, and ad hoc groups) in market/reliability entities such as NYISO, NYSRC, NPCC and NERC in terms of number and expertise of both assigned personnel and management oversight, particularly in areas and emerging issues that are expected to have a significant impact?
- Does PSEG LI 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 NYISO operations, NYISO billing, interpretations and applications of NYISO market rules (including the internal administrative compliance costs of participating in various markets); potential changes in market rules; interpretations and applications of NYSRC, NPCC and NERC reliability rules; potential changes in reliability rules, and results of planning studies conducted by the NYISO and others?
- Does PSEG LI 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 PSEG LI 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?

Findings and Conclusions

1. **Collectively, LIPA and PSEG LI provide coverage at stakeholder forums in RTOs and reliability organizations that are relevant to LIPA's operations and its customers' interests.**

    - LIPA and PSEG LI organizations responsible for wholesale market policy are shown in **Exhibit XIV-8**.

Exhibit XIV-8
LIPA and PSEG LI Organizations Responsible for Wholesale Market Policy



🟨 Responsible for wholesale market policy
Source: DRs 1 and 854.

- Primary responsibility for LIPA's regional wholesale power market policies and meeting coverage lies with personnel in LIPA's Operations Oversight Organization and PSEG LI's Power Markets.

    - LIPA's Director of Wholesale Market Policy, who reports to the VP Operations Oversight, is located in Albany and attends selected NYISO meetings. He also manages the activities of law firms representing LIPA's interests at FERC.
    - PSEG LI's Power Markets organization currently provides meeting coverage and support at NYISO, and manages the activities of an outside firm, Customized Energy Solutions (CES), which provides regulatory coverage at NYISO, PJM and ISO-NE.

- LIPA, PSEG LI, and its contractor - CES participate in most stakeholder groups that are relevant to LIPA business and operational interests.

- LIPA operates within the area governed by NYISO and thus focuses most of its resources on market and operational issues pertaining to that market. **Exhibit XIV-9** provides a summary of LIPA and PSEG LI NYISO committee representation.
  - PSEG LI's NY-PJM Market Policy Manager and LIPA's Director of Wholesale Market Policy attend the higher-level committees where participant votes are taken such as the Business Issues Committee (BIC) and the Management Committee (MC) as well as some of the lower tiered committees and working groups that are discussing issues deemed important to Long Island.
  - CES-NY covers most of the committee meetings and provides notes and feedback on some of the lower level committees and working groups on a weekly basis. If any relevant issues are raised at any of these meetings that require PSEG LI or LIPA to take a more active role they are subsequently brought up for discussion during the weekly RTO meetings each Monday.
  - All NYISO committees fall under the administrative guidance of the BIC, MC or Operating Committee (OC) in New York, all meeting dates and agendas are posted and LIPA is well represented at these meetings. As shown in **Exhibit XIV-9,** there are typically two LIPA representatives at these meetings.[8]

Exhibit XIV-9
LIPA and PSEG LI NYISO Committee Representation

Meetings	**Position**										
	LIPA - Director	**PSEG LI Mgr NY/PJM Markets**	**PSEG LI Chief System Operator**	**CES (Consultant)**	**PSEG LI Engineer – Trans. Planning**	**PSEG LI Engineer – Trans. Planning**	**PSEG LI -MGR Load Forecasting**	**PSEG LI MGR. NERC Compliance**	**PSEG LI Principal Elec. Sys. Op.**	**PSEG LI Principal Engineer – Trans. Plan**	**PSEG LI Principal Engineer – Prot &Tel.**
Monthly Meetings											
Budget & Priorities Working Group				✓							
Business Issues Committee	✓	✓									
Electric System Planning Working Group				✓							
Installed Capacity Working Group	✓	✓									
Management Committee	✓	✓									
Market Issues Working Group	✓	✓									
Operating Committee			✓	✓							
Systems Operations Advisory Subcommittee			✓								
Transmission Planning Advisory Subcommittee				✓	✓						

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[8] DR 625

Meetings	Position										
	LIPA - Director	PSEG LI Mgr NY/PJM Markets	PSEG LI Chief System Operator	CES (Consultant)	PSEG LI Engineer – Trans. Planning	PSEG LI Engineer – Trans. Planning	PSEG LI -MGR Load Forecasting	PSEG LI MGR. NERC Compliance	PSEG LI Principal Elec. Sys. Op.	PSEG LI Principal Engineer – Trans. Plan	PSEG LI Principal Engineer – Prot &Tel.
Bi-Monthly Meetings											
Systems Protection Advisory Subcommittee											✓
As Needed Meetings											
Billing & Accounting Working Group				✓							
CFR Steering Committee								✓			
Credit Policy Working Group				✓							
Electric Gas Coordination Working Group			✓								
Interconnection Issues Task Force			✓								
Interconnection Project Facilities Study Working Group						✓					
Load Forecasting Task Force							✓				
Management Liaison Subcommittee				✓							
Price Responsive Load Working Group				✓							
Restoration Working Group			✓								
TOP Working Group									✓		
Transmission Planning Working Group										✓	

Source: DR 149.

- As shown in **Exhibit XIV-9**, there is some duplication of NYISO meeting coverage by LIPA and PSEG LI. As discussed in Conclusion 4, under the A&R OSA, PSEG LI cannot take any regulatory position that potentially conflicts with Public Service Enterprise Group (PSEG) or any of its affiliates (See Conclusion 4). As a result, it is necessary to have both LIPA and PSEG LI representatives at key NYISO meetings in order to maintain proper representation as outlined under the A&R OSA.[9]

- PSEG LI uses its contractor - CES to monitor developments in PJM and ISO-NE and raise key issues as they arise for further action by LIPA and PSEG LI.

  - LIPA's ultimate ability to impact key RTO decisions and policy issues in these markets is generally limited due to its relatively small stake in the markets.[10]
  - A summary of CES' coverage of PJM and ISO-NE meeting coverage is shown in **Exhibit XIV-10**.

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[9] DR 622

[10] DR 625

Exhibit XIV-10
PJM and ISO-NE Meeting Coverage by CES

PJM	ISO-NE
Monthly	
Credit Subcommittee Demand Response Sub-Committee Energy Market Uplift Senior Task Force Load Analysis Subcommittee Market Implementation Committee Market Settlements Subcommittee Markets & Reliability Committee Members Committee Operating Committee Planning Committee Regulation Market Issues Task Force Transmission Expansion Advisory Committee Transmission Issues Task Force	Markets Committee Participants Committee Planning Advisory Committee Power Supply Planning Committee Reliability Committee Transmission Committee
As Needed	
Intermittent Resources Subcommittee Interregional Planning Stakeholder Advisory Committee PJM-Midcontinent Independent System Operator Joint Market Initiative Resource Adequacy Analysis Subcommittee	

Source: DR 149.

- PSEG LI participates in NPCC and NYSRC committees on behalf of LIPA.
  - NPCC is one of eight reliability regions which report to NERC, is responsible for promoting and improving the reliability of the interconnected bulk power systems in Northeastern North America, in which LIPA is located. NPCC also assesses compliance and conducts enforcement of the NERC standards. As such, LIPA/PSEG LI works closely with NPCC by participating in person on various NPCC committees and workshops to discuss topics and participate in projects that implement the NERC standards in the NPCC Region.[11]
  - LIPA is a member of the NYSRC. The NYSRC is an active participant in the development of NERC reliability standards and other NERC initiatives. PSEG LI, on behalf of LIPA, is an active participant in the NYSRC and participates in the NYSRC committee process which formulates positions on proposed NERC reliability standards and initiatives.[12]
  - As summarized in **Exhibit XIV-11**, PSEG LI's Transmission and System Protection Engineers routinely participate in NPCC meetings and PSEG LI's

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[11] DR 352

[12] DR 352

Manager of Capacity and Manager of Transmission Planning routinely attend NYSRC Meetings.

Exhibit XIV-11
PSEG LI Participation in NPCC and NYSRC Meetings

Meetings	Position						
	Transmission Engineer	Protection & Telecom Engineer	Sr. Manager Transmission Planning	Sr. Manager Transmission Operations	NY Market Capacity Markets and Policy Manager	Transmission Operations Engineer	Manager - Transmission Planning
NPCC							
Bi-Monthly							
Protection System Mis-Operation Review		✓					
Task Force on System Protection		✓					
Quarterly							
Reliability Coordinating Committee (RCC)							✓
As Needed							
Task Force on Coordination of Planning	✓						
NYSRC							
Monthly							
Executive Committee			✓				
Installed Capacity (ICAP) Subcommittee					✓		
Reliability Compliance Monitoring/Rules Subcommittee						✓	
Reliability Rules Subcommittee				✓			

Source: DR 149.

2. PSEG LI uses a consultant to provide coverage at PJM and ISO-NE, where LIPA has a relative small stake, and to provide coverage at NYISO meetings when necessary.

- CES is currently under contract to PSEG LI to provide primary committee coverage at PJM and ISO-NE as well as supplementary committee coverage to PSEG LI at the NYISO.
  - New York is the primary market of operation for LIPA. There are more than 20 committees and working groups at the NYISO that PSEG LI participates in and reports on for LIPA. These meetings, at times, occur simultaneously resulting in the need for multiple representatives. CES provides this additional coverage to PSEG LI.[13]
  - LIPA has some contract assets and market interests in PJM (Neptune Cable and Marcus Hook Generation). CES provides coverage of key market issues and

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[13] DR 623

committees which may have an impact on LIPA's assets and cost allocations in this market.[14]

  - LIPA also has contract assets and market interests in ISO-NE (NUSCO Cable, CSC, and Bear Swamp Pumped Storage Facility).[15]

- LIPA's relatively small stake in the PJM and ISO-NE markets does not currently justify the need for a full-time employee in these markets. LIPA's interests are more efficiently and economically served through the use of a third-party contractor such as CES.

3. **Although LIPA/PSEG LI's participation in regional power markets is split between LIPA, PSEG LI and consultants, there is an effective process to communicate issues and develop policy through weekly meetings.**

- There are two weekly meetings regarding policy and market structure issues:

  - **Monday ISO Working Group – Standing Call**. Monday's ISO Working Group call focuses on reports of meetings attended in the various ISOs/RTOs during the prior week, a report on significant FERC activity during the week, and an exploration of the relevance of the issues to LIPA.
  - **Friday Policy Call.** In the Friday policy call, LIPA, PSEG LI and Van Ness, LIPA's FERC consultant, meet to discuss policy and market structure issues in depth. The group discusses the technical merit of the market structure proposals active during the prior week and found relevant to Long Island, as well as alternatives to these proposals. The group also identifies prospective changes in market structures that would be in LIPA's interest. Legal strategies for addressing these issues are discussed as well.[16]

- In addition, LIPA's VP Operations Oversight has a weekly briefing call. NorthStar reviewed the briefing minutes from 2015 to September 2017 and found good coverage of current issues and active filings at the RTOs and FERC, as well as notes regarding LIPA's follow-up actions to issues raised.[17]

4. **There are no procedures regarding instances when there is a conflict between the interests between LIPA and PSEG LI with respect to wholesale market policy.**

- There are times that that PSEG LI cannot take the lead in advocating an issue at an RTO due to potential conflicts with Public Service Enterprise Group or any of its affiliates.[18] One potential conflict of interest between PSEG and LIPA is the question of cost allocation. In such cases, PSEG LI typically is silent on the issue.[19]

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[14] DR 623
[15] DR 623
[16] DR 298
[17] DR 755
[18] DR 622
[19] IR 4 and IR 111

- There are no documented policies or procedures that address conflicts of interest.[20] The A&R OSA does discuss conflicts of interest, stating that if PSEG LI identifies a potential conflict, PSEG LI and LIPA "shall engage in good faith discussions to reach a Conflict Resolution. If, notwithstanding such good faith discussions, a mutually acceptable Conflict Resolution is not promptly reached, the Service Provider shall, upon notice to LIPA, cease representation of LIPA."[21] The A&R OSA does not provide procedural guidance regarding the specific responsibilities of LIPA, PSEG LI, and PSEG Enterprise individuals to determine and respond to potential conflicts.

- The OSA acknowledges that PSEG LI's representation of LIPA before regulatory or industry parties may give rise to conflicts of interests and states that that "the Parties shall engage in good faith discussions to reach a Conflict Resolution. If, notwithstanding such good faith discussions, a mutually acceptable Conflict Resolution is not promptly reached, the Service Provider shall, upon notice to LIPA, cease representation of LIPA and LIPA shall obtain substitute representation."[22]

5. **LIPA and PSEG LI are pro-active in developing and advocating rule changes in in relevant stakeholder forums to help improve overall market efficiency and reliability as well as to support the interests of LIPA's rate payers.**

- 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 in the period 2014 to 2016, combined with the overall actions of each ISO, resulted in projected ten-year savings from $532 million to $744 million.[23]

- LIPA/PSEG LI identifies potential policy issues in its weekly market policy meeting.[24] Market Policy personnel consult with PSEG LI departments as necessary to examine emerging issues that may have an impact on reliability and/or cost. These groups/personnel determine whether and, if so when, an emerging issue may impact reliability and/or cost and develop an estimate of the impact on reliability and cost. Examples of such studies include:

  - Work performed in addressing the impact of NERC's N-1-1 reliability criteria. NERC requires utilities perform N-1-1 contingency analysis, which involves studying the impact of two sequential outages.[25]
  - Adoption of Zero Emissions Credits for those nuclear facilities located in upstate NY which were determined to be in financial distress.
  - Potential retirement of the Indian Point 1 and 2 nuclear units.[26]

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[20] DR 538
[21] DR 4 A&R OSA, p. 38
[22] DR 538
[23] DR 295
[24] DR 298
[25] http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=7464807
[26] DR 152

- Once a policy stance has been selected, LIPA, and where appropriate, PSEG LI staff, act within the relevant stakeholder forums to bring about the desired outcome.

    - LIPA and PSEG LI works in various caucuses and the larger stakeholder group to identify stakeholders supporting conflicting interests.
    - Proposals are refined where possible to address conflicting interests. Issues are discussed with the NYISO Market Monitoring Unit (MMU) to determine what is possible, economically efficient, and fair. (The MMU is responsible for ensuring that the markets administered by the ISO function efficiently and appropriately, and to protect both consumers and participants in the markets administered by the ISO by identifying and reporting market violations, market design flaws and market power abuses.)
    - Issues are discussed with NYISO staff to determine what is practically achievable given current structures, workloads, etc. The interests of broader groups of stakeholders supporting or opposing a measure are identified. Pivotal stakeholders and a value proposition for pivotal stakeholders are identified and discussed with these stakeholders.
    - Written and oral comments and refinements are made in stakeholder processes. Proposals and amendments are offered for vote to achieve voting majorities around favorable outcomes.
    - Where favorable outcomes are not achieved, LIPA makes opposing filings in FERC forums, and if necessary in court articulating issues and alternatives. [27]

- LIPA brought several issues before FERC in the 2014 to 2016 period, as summarized in **Exhibit XIV-12**.

    - LIPA's two principal FERC regulatory counselors, Van Ness and Stinson Leonard Street, also serve as FERC regulatory counsel to several large public power entities and provide advice to the American Association of Public Power and the Large Public Power Council, organizations in which LIPA actively participates to economically advance the ratepayers interest before FERC. [28]

Exhibit XIV-12
LIPA FERC Issues 2014 to 2016

Issue	Description
2014	
Billing Dispute Resolution	Van Ness helped work with NYISO on resolving a billing dispute arising from a period before PSEG LI was engaged.
Reference Pricing	Van Ness helped draft FERC filing opposing NYISO's formulation of unrecoverable gas penalties outside of gas emergency conditions (non-operational order flow periods).
Order 100	Van Ness worked with transmission owners and NYISO to carve out a role for LIPA Board in determining Public Policy Requirements pursuant to NYS statute.
Rate Schedule 10	Van Ness worked to design comparability standards for LIPA ratemaking

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[27] DR 152

[28] DR 296

Issue	Description
	pertaining to public policy transmission projects for inclusion in the NYISO tariff. This retains LIPA's statutory rate making authority.
2015	
Caithness II Minimum Interconnection Standard	Stinson and Leonard helped file with FERC, LIPA's perspective on including lower voltage multiple contingency conditions when assessing minimum interconnection requirements.
Ginna Nuclear Plant Reliability Support Services Agreement (RSSA)	The plant extended its operation under a local subsidy agreement.
Technical conference on whether to Include LI in the New Capacity Zone (currently G-J zone).	Van Ness reviewed LIPA testimony provided to FERC in technical conference.
Transco Rate Filing	Van Ness supported confidential settlement discussions regarding Transco rates and Transmission Owner Transmission Solutions project cost allocations, helping to reduce LI's cost burden.
Y49 Outage Cost	Holland and Knight supported LIPA in cost recovery litigation for Y49 cable anchor dragging outage 2016.
2016	
IPPNY BSM Complaint (EL13-62-002)	Independent Power Producers of NY (IPPNY) asserted that buyer-side market (BSM) power mitigation measures should apply to ROS zone.
DPS Demand Response Complaint	Transmission Owners collectively filed a complaint.
Environmental Protection Agency Clean Power Plan	Van Ness helped LIPA review plan legal requirements, basis, and alternative compliance alternatives.
Historic Fixed Price Transmission Congestion Contracts	LIPA negotiated favorable and equitable rules and supported NYISO filing of these rules.
Market Based Rate Notification of Intent	Van Ness advised LIPA on Market Based Rate rule implications and history.
Michigan Phase Angle Regulating Transformers (PARs) Rate Case	Helped support initial decision in the Michigan PARs case finding that the PARs were not added for the benefit of New York, and could not be cost allocated to New York.
Order 1000	Van Ness continued to work to include language allowing LIPA Board to decide Public Policy Requirements on LI which drive transmission.
PJM Regional Transmission Expansion Planning Cost Allocation Settlement	Van Ness filed challenging PJM's assertion that all loads benefitted equally from short- circuit and other protections which it was attempting to allocated to LI.
LI Public Policy Requirements (PPR) Assessment	Van Ness worked with PSEG LI to assure that LI PPR solicitation and evaluation rules were followed, and to facilitate the PSEG LI review of these PPRs.
Ramapo PAR	Van Ness supported confidential settlement discussion aimed at getting a participant funding agreement among PJM and NYISO ratepayers.

Source: DR 296.

C. POWER AND FUEL SUPPLY CONTRACTS

Evaluative Criteria

- Does LIPA audit, enforce and manage the A&R PSA to effectively and efficiently balance reliability with low cost electricity for its customers?

- Does LIPA audit, enforce and manage its FMA to effectively and efficiently balance reliability with low cost electricity for its customers?
- Does LIPA audit, enforce and manage its PSMA to effectively and efficiently balance reliability with low cost electricity for its customers?
- Does LIPA/PSEG LI have appropriate resources to oversee the fuel management and power supply contracts? If not, does LIPA effectively use outside resources to monitor PSEG LI's performance on the agreements?
- Does PSEG LI have financial and physical hedging practices as they relate to electric transmission, including the role and use of transmission congestion contracts and rights used in the NYISO's wholesale market? (See Section D)
- Does LIPA take appropriate action when PSEG ER&T does not meet performance standards or comply with contractual requirements? (The RFP uses the term PSEG LI, rather that PSEG ER&T.)

Findings and Conclusions

6. PSEG LI Power Markets has appropriate oversight and management of the A&R PSA.

- In accordance with Section 4.2(A)(6)(c) of the A&R OSA, PSEG LI assumed responsibility for the functions of LIPA's Power Supply group, including oversight and management of the A&R PSA.[29] LIPA's Director of Operations Oversight oversees PSEG LI's oversight of power supply contracts, including the A&R PSA.[30]

- Power Markets' Power Resources and Contract Management group provides contract management for the A&R PSA and other all power purchase and firm transmission service agreements. Those services include:

  - Review and approval of monthly invoices for payment
  - Dispute resolution of incorrect invoices
  - Contract termination/extension evaluations and recommendations
  - Contract amendment negotiations.[31]

- Power Markets has a formal, detailed procedure which delineates the processes for processing of purchased power invoices under its purview, creation and review of related reports and the review and approval of capital improvement projects pertaining to the PSA.[32]

- Power Markets has a Generation Analysis Manager dedicated to PSA oversight, who is supported by the current Manager of Generation stationed at NMP2, who previously was directly responsible for PSA oversight.

- PSEG LI's PSA oversight responsibilities include

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[29] DR 426
[30] DR 683
[31] DR 426
[32] DR 153

  - Annual review of the development of the annual PSA Capacity Charge. This process includes a review of:

    - Proposed capital budget
    - PSA variable costs
    - Other O&M expenses
    - Escalation rates used for the labor and benefits cost indices
    - Maintenance schedule.[33]
  - Annual review of "true-up" calculations including property taxes and plant additions.
  - Review of actual plant operating characteristics including: heat rate, forced outage rate, availability and equivalent availability factors.
  - Monthly invoice review.
  - Review of proposed changes to the capital budget.
  - Review of all major forced outages to determine cause, impact and responsibility.[34]

- PSEG LI Power Markets reviews NG Generation-proposed capital projects. Power Markets is authorized to approve NG Generation projects if the approval does not cause the capital budget to exceed the LIPA Board-approved annual capital budget related to NG Generation projects.

  - National Grid submits its proposed annual five-year capital improvement plan to Power Markets at least 90 days before the start of the contract year.[35]
  - National Grid's submittal includes a project justification document for each project that requires approval to start in the upcoming budget year.[36]
  - Power Markets reviews each project and supporting documentation, and works with National Grid if additional information or analysis is needed. The objective of the review/analysis is to make an informed and rational decision on whether or not to recommend approval of a project.[37]
  - National Grid is required to submit a project justification only for projects that are scheduled to begin in the immediate budget year. Power Markets' review and approval of projects may take place outside of the budget cycle in order support project schedule requirements.[38]

- Power Markets denies or modifies some of National Grid's proposed capital projects. Typical reasons for Power Markets' exclusion or modification of proposed PSA projects include:

  - Changing maintenance schedules.
  - Permit delays.

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[33] DR 153

[34] DR 153

[35] DR 153 Attachment

[36] DR 640

[37] DR 153 Attachment

[38] DR 153 Attachment

  - Project replaced with alternative design.
  - An alternative project contained in the National Grid project justification is more cost effective.
  - PSEG LI develops an alternative project or approach.
  - Cost-benefit analysis is not sufficient.
  - PSEG LI determines that there are cost effective operational workarounds to the project.
  - PSEG LI determines that plans for potential retirement do not justify the investment in the project.
  - New unanticipated projects come up after submittal of the plan, so that projects may be deferred to keep within the total capital budget plan or to provide National Grid manpower for the new projects.[39]

- In 2016, Power Markets approved $34.2 million of NG Generation's proposed capital expenditures of $45.5 million. During the first half of 2017, Power Markets denied approval or did not approve the originally proposed scope for two projects totaling $4.9 million.[40]

- In accordance with the PSA, NG Generation provides Power Markets with quarterly operating reports (electricity delivered and fuel burned), capital variance reports, and planed outage schedules. Power Markets reviews these reports with LIPA staff.[41]

- NG Generation issues monthly PSA unit performance data for PSEG LI's review. Under the A&R PSA, NG Generation receives penalties if heat rate and unforced capacity (UCAP) performance targets are not met.[42] LIPA has not had cause to invoke any penalty payments under the A&R PSA.[43] PSEG LI Power Markets reviews and approves monthly invoices for the PSA and other PPAs.

- Power Markets calculates and creates independent power producer (IPP) and FIT invoices, and verifies and approves on-island (including PSA) and off-island supply invoices and the NMP2 invoice (Call for Funds).

  - On-island PPA facilities have a LIPA revenue grade meter. Power Market sends energy meter data to the counter parties for invoice preparation.
  - On-island IPP and FIT facilities also have LIPA revenue grade meter. Power Markets uses this energy meter data for invoice preparation.
  - Off-Island supplies do not have a LIPA meter; Power Markets uses reports from the PJM, ISO-NE and the NYISO to verify deliveries.
  - The NMP2 Call for Funds is checked against the approved budget for NMP2.
  - NG Generation prepares PSA Capacity, PSA Variable, and PSA RGGI invoices, which are verified by PSEG LI.

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[39] DR 634
[40] DR 634
[41] DR 635 Attachment 1 CONFIDENTIAL
[42] DR 4 A&R PSA
[43] DR 154

  - NG Generation develops the PSA Variable invoice using revenue grade meters it owns and maintains. Power Markets performs a rough check of energy output using NYISO energy meter data provided by ER&T.
  - NG Generation develops two annual adjustments to the monthly capacity charge: 1) to reflect the impact of capital additions and an allowance for property taxes, and 2) to reflect changes in Pension and Other Post Employment Benefit (OPEB) expenses. NG Generation submits documentation and work papers in substantiation of these adjustments. Power Markets reviews this documentation to ensure that the adjustments are in compliance with contract terms. In the case of Pension & OPEB, Power Markets reviews the adjustments in cooperation with LIPA's financial personnel.
  - NG Generation develops PSA RGGI invoices. Power Markets does an approximate check of the tons of carbon dioxide emissions for which allowances are being invoiced against the tons of carbon dioxide emissions calculated from the fuel burned in the generators.

- All invoices must be reviewed by at least three Power Markets' personnel. Power Markets submits an invoice package to PSEG Services Corporations' Accounts Payable group for payment and to LIPA for review.[44] PSEG Services Corporation is shown in **Exhibit XIV-13** in Conclusion 7.

- NorthStar reviewed sample invoice packages and found them to be complete with appropriate documentation of PSEG LI review and approval.[45] The Invoice Package includes:

  - Invoice
  - Supporting documentation
  - Invoice review checklist
  - Required level of approval signatures
  - Email trail.[46]

- Power Markets' purchased power invoice process is subject to an OSA performance metric that is intended to measure and incent both the timeliness and accuracy of the monthly invoice process. The metric relates to all invoices under the purview of Power Markets, except for FIT invoices. PSEG LI's year-to-date results through September 2017 show 99.5 percent of invoices were accurate and paid in a timely manner.[47]

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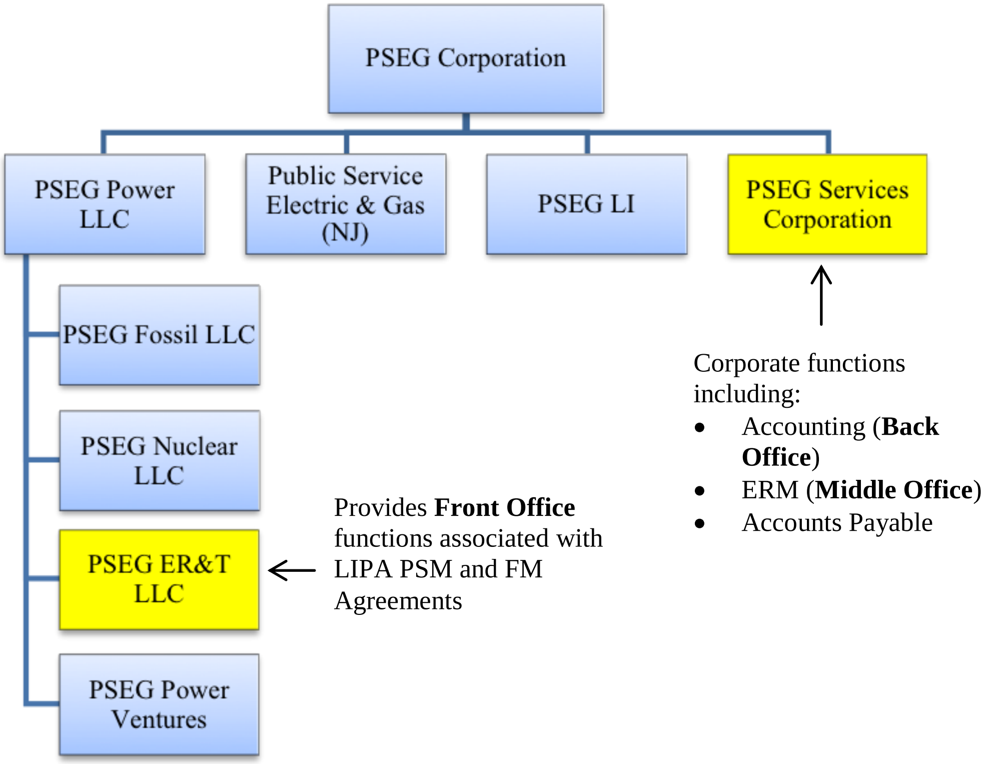
[44] DR 153 Attachment
[45] DR 630 CONFIDENTIAL
[46] DR 153 Attachment
[47] DR 936

7. **The PSMA and FMA specify that PSEG ER&T must organize its functions into front, middle, and back-office organizations. This structure facilitates LIPA's oversight and management of the contracts, as the principal role of the middle office is to monitor the fuel and power supply activities and provide oversight reports to LIPA.**

   - LIPA first established a front, middle, and back-office fuel management structure for its externally-sourced power supply and fuel, supply management functions in its contracts with CEE, its PSM and FM provider until PSEG – ER&T assumed these responsibilities on January 1, 2015. (As previously explained, the A&R gave PSEG LI the right to provide power supply management and fuel supply management services commencing January 1, 2015.) This management structure reflects the separation of responsibilities common in the financial services industry. In short, the front office executes transactions, the middle office monitors the front office, and the back office prepares invoices and pays bills.

     Exhibit XIV-13 shows the PSEG organizations that perform front, middle, and back office PSM and FM functions for LIPA.

Exhibit XIV-13
PSEG Organizations Performing Front, Middle and Back Office PSM and FM Functions for LIPA



Source: DR 583.

- Although LIPA has separate power supply and fuel supply agreements with PSEG ER&T, the activities are managed jointly by PSEG ER&T.
  - In accordance with the PSMA, the PSEG ER&T provides front and back office services, and designates its affiliate, PSEG Services Corporation, as the middle office service provider.
  - Although not specified in the PSMA, PSEG ER&T also chose PSEG Services Corporation to provide back office support for its LIPA work, as it provides similar support for PSEG ER&T's other work.[48]
  - PSEG Services Corporation provides management and administrative services to PSEG and its subsidiaries, including PSEG LI. These services include: accounting, communications, human resources, information technology, treasury, and procurement.[49]

- The middle office monitors PSEG ER&T's power supply and fuel supply activities. **Exhibit XIV-14** provides a summary of PSM and FM front, middle, and back-office responsibilities. In addition to typical middle office services, PSEG Services ERM monitors ER&T's compliance with LIPA's hedge plan and retains LIPA's hedge advisor. (See Conclusions 24 to 26 for further discussion.)

Exhibit XIV-14
Power Supply Management and Fuel Management Front, Middle, and Back Office Activities

Function/ Organization	Key Activities
Front Office PSEG ER&T	**Daily** • Forecast of load and fuel requirements • Bidding of generation, cables and load to ISOs –least cost operations • Physical purchases of fuel to meet requirements • Coordination with all "touch points," including generators, cables, fuel supply, fuel transportation, and ISOs • Execution of transactions in accordance with LIPA Power Supply Hedge Plan **Monthly/As Required** • Negotiation of new contracts • Participation in the ISO/RTO and bilateral capacity resources markets
Middle Office PSEG Services ERM	• Monitoring of ER&T performance under ER&T LIPA contracts • Trade confirmations, compliance, and settlements • Spot and forward pricing used to value positions • Counterparty credit risk • Obtain hedge advisory services • Monitoring of ER&T compliance with LIPA approved hedge plan • Mark-to-market hedge report to LIPA
Back Office PSEG Services Accounting	• Maintain books and accounting records • Bill validation/settlement • Payments and invoices

Source: DR 4 PSM Contract, FM Contract, DR 284.

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[48] DR 195

[49] DR 195

8. **LIPA has appropriate resources to manage and enforce the fuel management and power supply contracts with PSEG ER&T.**

   - LIPA's Director of Power and Fuel Supply Services is responsible for oversight of the PSMA and FSMA. The current director has significant experience and has held this position for over five years and has the requisite expertise and experience for effective oversight.

   - LIPA's Director of Power and Fuel Supply Services oversight responsibilities include:

     - Monitor load forecasting results and process to maintain accuracy within acceptable parameters.
     - On a seasonal, monthly, weekly, and a "day ahead and intra-day" basis, ensure appropriate volumes of physical fuels are available to support LIPA's customer needs, while keeping imbalance charges to an acceptable level.
     - Monitor flow of bids and offers to appropriate ISO's, in regards to PSM and FM activities, in support of LIPA's customer load requirement.
     - Monitor cable performance as cable schedules can have a significant effect on overall system dispatch.
     - Oversee in-day, real-time fuel and power supply operations, looking for anomalies and inefficiencies, and bringing them to the attention of the PSM and FM service providers.
     - Ensure close coordination and communication with generation owners, system operations, Power Asset Management, Operations, and the ISOs with which LIPA conducts business.
     - Monitor PSM and FM performance to ensure continued operations are reliable and risk-adjusted least cost.[50]

9. **LIPA has effective processes for on-going detailed monitoring and review of PSEG ER&T's fuel and power supply activities. LIPA does not rely on audits for oversight of PSEG ER&T, but has performed one audit of PSEG ER&T activities,**

   - LIPA's processes to oversee the fuel management and power supply contracts include: daily, monthly, and annual reviews of contract performance metric performance; routine meetings with PSEG ER&T; and, daily operations reports.

   - PSEG ER&T's performance is measured, monitored, and contractually bound by PSM and FMA Metrics. There are several routine reports to LIPA and meetings which address PSEG ER&T's metric performance.

     - **Daily PSM report** – Snapshot of previous day's metric results, produced and reviewed by PSEG Middle Office and LIPA.
     - **Daily FM report** – Snapshot of past days FM metric results, produced and reviewed by PSEG Middle Office and LIPA.
     - **Monthly Metric meetings** – On a monthly basis, PSM, FM, MO, and LIPA review and discuss previous month's metric results.

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[50] DR 683 Attachment 2

  - **Annual Metric Meeting** – PSM, FM, MO, and LIPA meet annually to review the past year's metric results.

- LIPA's Director of Power & Fuel Supply Services has number of routine meetings and calls with PSEG ER&T to discuss operational issues.

  - **Daily Operations Call** - Every day, LIPA's Director of Power & Fuel Supply Services and a PSM Electric Analyst conduct an operations call to discuss the day-ahead system dispatch plan, including the NYISO day-ahead generation awards, NYISO bid types, corresponding fuel volumes, peak load, total megawatt hours, expected cable flows, off-system sales/purchases, virtual bids, next day fuel prices, and expected NYISO energy prices.
  - **Monday Morning Operations Meeting -** At 9:00 AM each Monday, representatives from LIPA, PSEG ER&T Front and Middle offices, NG Generation, PSEG LI Power Asset Management, and NG Generation Environmental, discuss the prior week's performance, and the expected current week's operations. Topics covered include load forecast, weather, cable/tie-line constraints, generator status / maintenance, fuel price, fuel volume/inventory, and natural gas balancing results.
  - **Ad Hoc Calls –** LIPA's Director of Power & Fuel Supply Services communicates with ER&T throughout the day regarding various topics and issues. Common topics are Pi Screen system dispatch information (current load verses forecasted load), and NYISO out-of-merit messages (in-day generator status changes).
  - **Monthly Baseload Natural Gas Meeting** between FM and LIPA to discuss volume of baseload gas to purchase for the next month. As per typical portfolio management, LIPA enters a new month with a ratio of fixed and floating priced natural gas. FM and LIPA determine the volumes to purchase based on various factors, including forward prices and forecast natural gas need.
  - **Bi-Annual ICAP** meeting to discuss LIPA's installed capacity (ICAP) needs and NYISO Auction purchases. PSEG ER&T, PSEG LI, and LIPA meet to discuss and review, the state of capacity in NYS, projected capacity requirements, related regulations, and the recommended capacity auction plan. ER&T also sends an email detailing PSEG ER&T's recommended NYISO Capacity Auction bid strategy. LIPA reviews the recommendation, then approves if LIPA concurs with the plan.[51]

- PSEG ER&T and LIPA have developed a full set of policies and procedures that cover all aspects of power supply management, fuel management, and middle office procedures activities.

  - The Director of Fuel and Power Supply Services ensures that PSEG ER&T and PSEG Services ERM maintain, update and comply with the Policies and Procedures.[52]

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[51] DR 49

[52] DR 49

- NorthStar reviewed the procedures and found them to be current and provide sufficient detail to execute the work.

- LIPA also receives daily PSM and FM operations reports, as summarized in **Exhibit XIV-15**.

Exhibit XIV-15
Daily PSM and FM Operations Reports

Reports	Description
Load Forecast	Compares the forecasted load to actual load, weather error, and model error. The load forecast is the foundation, the starting point by which most system strategies begin. This report helps ensure load forecast anomalies are noticed, reported, and addressed in an expedient and timely manner.
Fuel Estimate	This report establishes the amount of fuel needed for tomorrow's system dispatch. This report evolves as the fuel estimate for the next day evolves. The first estimate is before the NYISO determines the day-ahead schedule based on day-ahead bids.
Day Ahead Award	This report is the primary basis for the Daily Operations Call. It shows generator dispatch for tomorrow, hourly day-ahead ISO awards, expected load, ISO bid types, off system sales, virtual bids, and day-ahead locational based marginal price.
Heads Up	Final day-ahead generation fuel requirements for next day generator dispatch. This report is referenced during the Daily Operations Call. In contrast to the Day Ahead Award report (12:00 am to 12:00 am), the Heads Up report follows the gas day (10:00 am to 10:00 am).
Natural Gas Trade	Physical gas supply transactions for next day. The report details counterparty, volume, price, and effective dates. This report is printed from ER&T's trade capture system (Aligne) - the system of record. Any changes or edits to the transactions in Aligne are recorded and notifications that modifications were made are sent out. This report allows LIPA to ensure that transactions are with approved counterparties, certain counterparties are not receiving too much business, volumes are appropriate, prices are in line with market, and effective dates coincide with dates of usage.
Cable Schedule	Shows proposed schedule for the next day.
Cable Performance	Day-after results on positive dollars realized verses all potential positive dollars. This report displays clearly how the cable asset performed. This allows LIPA to closely monitor whether cable strategy is working as intended.
Gas Balancing	Details how the gas day ended (i.e., in-or-out of balance). This report is used to monitor the extent of gas imbalance issues, by volume and cost.
NMP2/Fitzpatrick Transaction Confirmation	Counterparty email exchange confirming hourly energy volumes to be received under the bilateral arrangements of nuclear contracts. Without this daily routine of confirming the transaction, the NYISO would not recognize the bilateral transaction resulting in a no flow for the day. By way of LIPA being copied on this email exchange, LIPA can verify that the transaction will flow.

Source: DR 49.

- In 2015, LIPA's Internal Audit performed a review of PSEG ER&T's fuel oil procurement. The audit determined that PSEG ER&T's controls were adequate and identified no exceptions.[53]

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[53] DR 904 Attachment 6

10. LIPA uses performance metrics to enforce and manage the PSMA and FMA. PSEG ER&T's performance metric results show compliance with contract requirements.

- The PSMA and FMA have performance metrics.
  - PSEG ER&T is assessed a penalty for sub-par performance; performance in excess of targets can be used to offset below target performance in other metrics; however, there is no additional compensation associated with being above the target.[54]
  - The Middle Office tracks ER&T's PSM and FM performance.
- As shown in **Exhibit XIV-16**, PSEG ER&T has exceeded its targets for almost all measures.

Exhibit XIV-16
PSEG ER&T PSM and FM Metric Performance

🟨 Performance within Tolerance   🟩 Performance above Target

Metric	Weight	Description	Target	2015	2016	YTD as of Aug. 2017
PSM Metrics						
Cable Transaction Effectiveness	10%	Potential day-ahead cost saving using the Neptune and Cross Sound cables. $\% = \frac{\text{Actual Cost Savings}}{\text{Potential Cost Saving}}$	2015 CSC: 45.2% Neptune: 65.5% 2016 Joint:70.6%	CSC 62.5% Neptune 64.3%	85.5%	81.1%
Critical Report Timeliness	10%	PSEG ER&T's timeliness in submitting daily, weekly and monthly critical reports. $\% = 1 - \frac{\text{\# of Late Reports}}{\text{Total Reports}}$	95%	98.5%	99.5%	99.6%
Generation Bid Accuracy	10%	Measures deviations from agreed-upon bidding guidelines. $\% = 1 - \frac{\text{\# Unit Hours outside bid range}}{\text{Total Unit Hours}}$	98%	99.8%	99.9%	100.0%
Adherence to Bidding Strategy	10%	Adherence to bidding strategy for load bids, Bear Swamp scheduling, CSC scheduling, and Neptune scheduling (weighted equally).	98%	99.5%	99.7%	99.8%
Contingent Bid Responsiveness	5%	Responsiveness in adjusting bids submitted to the NYISO, ISO-NE, and PJM, or taking other actions or no action, based on the occurrence of contingent events. = 1- .8(late-reported events/total contingent events)-.2(incorrect reporting on sample days/sample day events)	95%	99.1%	99.3%	99.9%

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[54] DR 49

Metric	Weight	Description	Target	2015	2016	YTD as of Aug. 2017
Annual Significant Financial Losses	10%	Incidents that are not covered by other metrics that result in loss greater than $100,000.	0	0	0	0
Load Forecasting	10%	Forecast of LIPA's load obligations used to bid into the NYISO. *= ABS(FORECAST LOADh - ACTUAL LOADh)*/ACTUAL LOADh	5%	3.0%	3.26%	3.7%
Capacity Market	5%	ER&T's purchases of capacity to meet Statewide Capacity Obligation at a cost lower than the statewide auction process = ((CAPCOST) - (MW OBLIGATION X CAPPRICE AUCTION))/MW OBLIGATION	0	-0.03	.03	-.01
Overall Satisfaction	30%	LIPA Management Team's [Note 1] assessment performance in 6 areas. Ratings from 1 to 5.	3	4.4	4.1	4.3
FM Metrics						
Gas Price Forecasting	15%	Accuracy of natural gas price forecast estimate by pipeline. Compared to the Gas Daily Settle prices.	Calculated Tolerance bands +/- 25%	9.7%	10.5%	7.1%
Gas Purchase Price	15%	Weighted average price for natural gas in the day ahead market, by pipeline, compared to Gas Daily Price by pipeline.	Calculated Tolerance bands +/- 25%	-0.1%	-0.1%	-0.2
Gas Balancing Charge	15%	Calculate cash-out factor by looking at cash-out dollars (for imbalances) as a percentage of total gas supply costs for the LIPA generating units.	.25%	0%	0%	0.0%
Overall Satisfaction	30%	LIPA Management Team's [Note 1] assessment performance in 6 areas. Ratings from 1 to 5.	3	4.5	4.1	4.3
Oil Inventory Monitoring	10%	Daily inventory of LIPA's oil tanks compared to minimum inventory, target level, and tolerance level. Benchmark reflects the percentage of days with no exemptions.	98%	100%	100%	100%
Invoice Processing Effectiveness	15%	Timeliness of Invoice Summary to LIPA and payments to counterparties.	98%	100%	100%	99.7%

Note 1: LIPA Management Team is defined as the Managing Director of Contract Oversight, Director of Power and Fuel Supply Services, and the Controller.
Source: DR 585 Attachment 2, DR 849 Attachments 1, 2, and 3 CONFIDENTIAL.

11. **LIPA and PSEG ER&T have an effective process to follow up on incidents of PSM and FM non-compliance through Corrective Action Forms.**

    - PSEG ER&T issues a Corrective Action Form (CAF) to formally identify any PSM/FM errors, and the corrective action taken as a result of the error. LIPA receives the CAF reports.

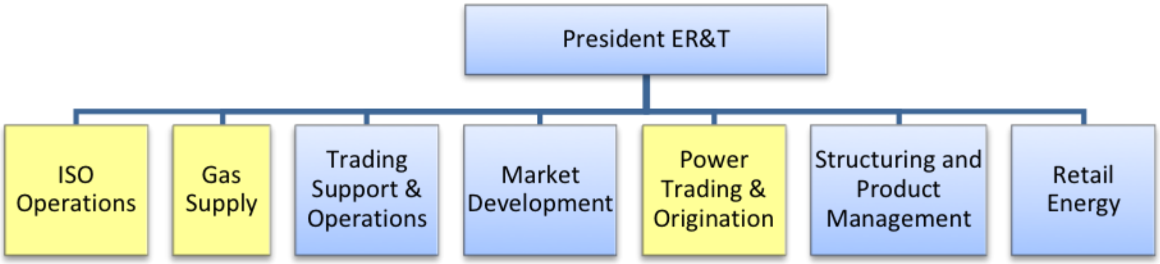
        - The focus is on improvement, not punishment.
        - The CAF may highlight improvements to the overall procedures, the root cause of deviation from the normal strategy, and the corrective action being taken (where applicable) moving forward to mitigate future instances of the same or similar results.
        - When applicable, an estimated financial impact of the non-conforming bidding strategy is provided.[55]

12. **PSEG ER&T provides services to entities in addition to LIPA, and has taken steps to ensure there are no conflicts of interest. NorthStar did not identify any conflicts of interest.**

    - PSEG ER&T conducts business with numerous counterparties including corporate affiliates. For example, it provides basic gas supply service for PSEG&G (New Jersey); it also markets the output of PSEG Power's generation assets, acquires and hedges fuel and power, economically dispatches plants and trades energy and various energy-related products.

    - **Exhibit XIV-17** shows the PSEG ER&T groups that provide PSM and FM services to LIPA.

Exhibit XIV-17
PSEG ER&T Organization Chart



🟨 Provides PSM and FM Services to LIPA
Source: DR 583, DR 852.

- PSEG ER&T has taken steps to ensure there are adequate separation of duties/ absence of conflict of interest, including:

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[55] DR 285 and 49

- ISO Operations has a dedicated LIPA team that is responsible for the day-ahead bidding/scheduling associated with approximately 6,000 MW of LIPA's owned/ tolled generation and cable assets as well as a dedicated 24/7 position associated with real time operations.[56]
- Gas Supply also has a dedicated LIPA team responsible for daily and monthly physical gas procurement – associated with providing the gas supply necessary to fuel the LIPA tolled generation assets. Other fuel supply functions, such as oil procurement/ scheduling, do not have dedicated LIPA resources due to the nature as well as the volume of the work required for LIPA.[57]
- Power Trading & Origination does not have a dedicated LIPA Team.[58] However, separate trading books are maintained for LIPA trades and PSEG ER&T trades, and access is limited based upon trader responsibility. Traders have explicit delegations of authority with respect to product, term, duration, notional value and company. Transactions for LIPA are separate from PSEG ER&T trades. A copy of each day's trade activity is sent to LIPA and the Middle Office every evening (Middle Office also has direct access to all trade information).[59]
- Both the Gas Supply and Power Trading & Origination organizations support LIPA's financial hedging. While neither organization has a dedicated LIPA hedging team, the financial transactions for LIPA are defined by the LIPA-approved hedge plan.[60]
- Middle and Back Office personnel do not report to PSEG ER&T.
- There is no comingling of trades. Transactions for LIPA are separate from PSEG ER&T trades. LIPA transactions are entered into by PSEG ER&T as agent for LIPA. The confirmation process validates this activity daily as well as the book owner validates the correct trades are in the correct books daily. A copy of each day's trade activity is sent to LIPA and the Middle Office every evening. The Middle Office also has direct access to all trade information.
- Separate trading books are maintained for LIPA trades and PSEG ER&T trades, with access limited based upon trader responsibility. Traders are unable to move trades between books and trades are required to be entered into the appropriate trading book reasonably contemporaneously with the trade itself. Traders have explicit delegations of authority with respect to product, term, duration, notional value and company.[61]

D. PSEG LI'S SUPPLY PROCUREMENT

Evaluative Criteria

- Does PSEG LI have appropriate supply portfolio principles, goals and objectives?

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[56] DR 852
[57] DR 852
[58] DR 852
[59] DR 583
[60] DR 852
[61] DR 583

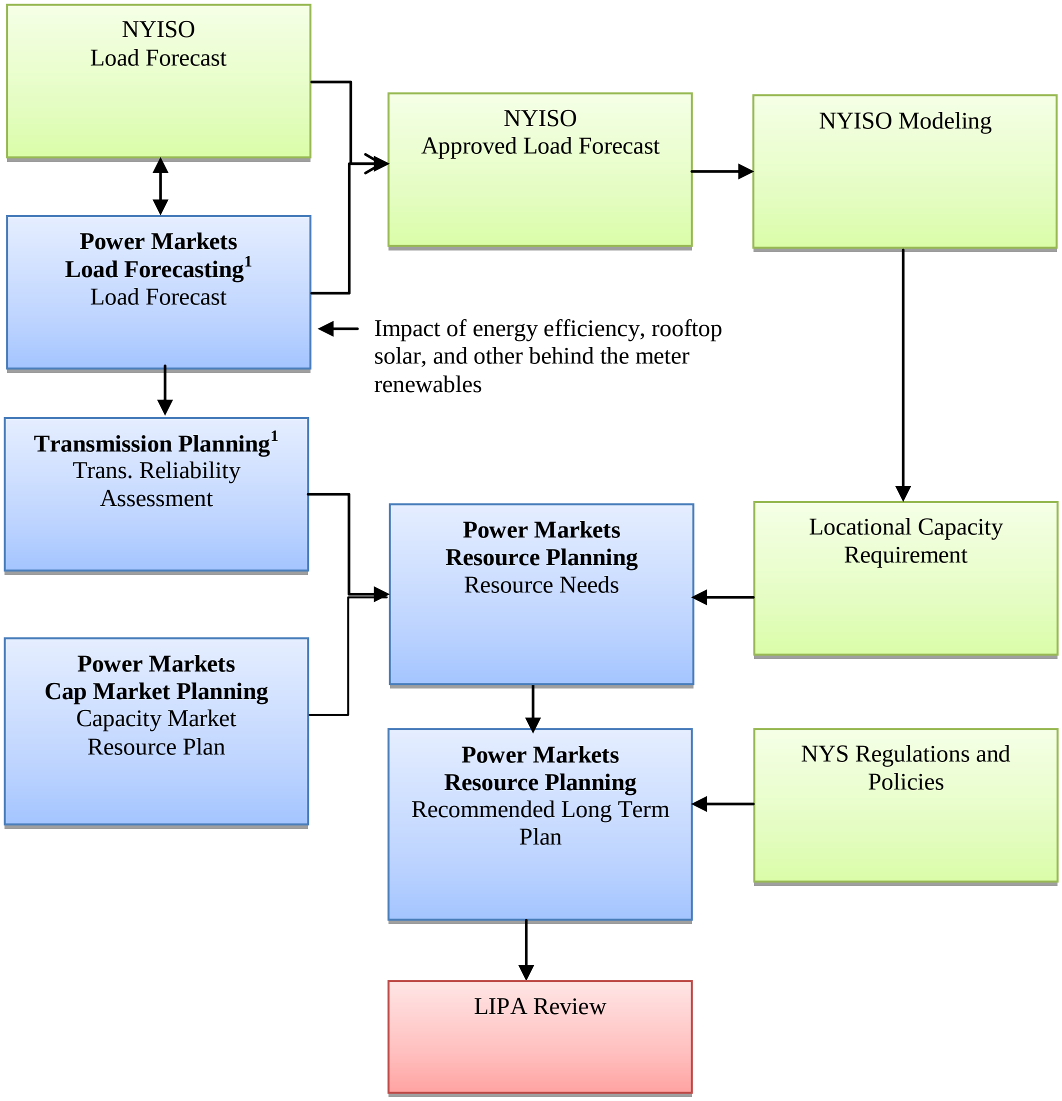
- Does PSEG LI's existing and planned power supply portfolio include the appropriate use of alternate energy sources (e.g., hydropower, wind, energy storage, etc.)?
- Does PSEG LI set appropriate portfolio performance goals?
- Is the current and proposed use of on-island generation provided by NG Generation effective and efficient?
- Does PSEG LI have appropriate supply procurement strategies, policies, processes, and methods, including as it relates to fuel purchased for the on-island generation?
- Does PSEG LI use supply procurement performance benchmarking with other utilities in an appropriate manner to improve and monitor procurement performance?
- Does PSEG LI have financial and physical hedging practices as they relate to electric transmission, including the role and use of transmission congestion contracts and rights used in the NYISO's wholesale market?
- Does PSEG LI use appropriate methods to evaluate the effectiveness of its supply portfolio with respect to price volatility and cost?
- Does PSEG LI have appropriate risk management strategies and practices?
- Does PSEG LI have appropriate financial and physical hedging practices for supply?
- Are PSEG LI's organizations and processes to oversee power supply activities appropriate and effective?
- Are demand management/response, energy efficiency, and migration of retail customers to completive supplies factored into the portfolio and procurement processes in an appropriate manner? See also **Chapter VII – Load Forecasting, System Planning and Distributed System Platform (DSP) Development**.

Findings and Conclusions

13. PSEG LI appropriately develops LIPA's energy supply portfolio to meet the NYISO and NYSRC capacity requirements, the NYISO approved load forecast (that includes energy efficiency impacts), and transmission reliability requirements.

- **Exhibit XIV-18** provides an overview of the process to develop LIPA's supply portfolio.

Exhibit XIV-18
Overview of Process to Develop LIPA's Supply Portfolio



[1] Load Forecasting and Transmission Planning are discussed in Chapter VII – Load Forecasting, System Planning and Distributed System Platform (DSP) Development.
Source: DR 156.

- LIPA's energy and capacity supply planning process includes the identification of the needs at the state (New York) and local (Long Island) levels.
  - As a NYISO member, LIPA participates in the NY State Planning Process which includes participation in various organizations and initiatives, such as the State Resource Plan, NYSRC, and various NYISO committees and working groups.
  - NYSRC sets the Installed Reserve Margin (IRM) requirement.

  - NYISO determines the Locational Capacity Requirement (LCR) for the Localities of New York City (Load Zone J), Long Island (Load Zone K), and the G-J Locality (Load Zones G, H, I, and J).
  - LIPA's capacity planning is based on the Long Island transmission district (Zone K) requirements. Zone K includes the Long Island municipalities (Freeport, Greenport, and Rockville Center) and load served by the New York Power Authority that is physically located on Long Island.
  - LIPA's load forecast, which includes the effects of energy efficiency and demand management, is a factor in determining the LCR.[62]

- Power Markets also considers local reliability needs and constraints in determining resource needs.

  - As discussed in **Chapter VII – Load Forecasting, System Planning and Distributed System Platform (DSP) Development**, T&D Planning's annual Summer Operating Study determines local reliability needs (bulk and non-bulk transmission).
  - T&D Planning runs a load flow analysis that identifies locally constrained areas or areas that are at risk of being constrained in the near future.[63]

- LIPA also assesses changing regulatory and policy requirements which can also impact the need for future resources.[64] As discussed in Conclusions 1 and 3, Power Market's Capacity and Policy group is also involved in regional power markets.

14. PSEG LI's Power Markets effectively oversees and performs long-term power supply activities.

- Power Markets' Load Forecasting group develops the load forecast (See **Chapter VII – Load Forecasting, System Planning and Distributed System Platform (DSP) Development**.)

- Power Market's Capacity & Policy group compares annual resource levels to state and local requirements in order to assess short-term and long-term compliance.[65] The Capacity & Policy group maintains a database of all active and proposed resources used to meet LIPA's capacity and energy requirements, this database includes:

  - NYISO IRM and LCR requirements
  - Approved peak load forecasts
  - Approved market transactions
  - Contract supply information.[66]

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[62] DR 156
[63] DR 156
[64] DR 156
[65] DR 156
[66] DR 155

- Power Market's Manager of Resource Planning is responsible for energy supply planning, and analyzes the economic operation of the system based on long-term load and fuel forecasts, existing and future supply resources, and system transmission limitations.[67]

15. PSEG LI used appropriate supply portfolio principles goals and objectives to develop LIPA's 2017 draft IRP, including the use of renewable power.

- An IRP is a long-term study of the electric system that reflects a comprehensive consideration of assumptions, alternatives and uncertainty.[68]

- LIPA's previous electric resource plan was issued in 2010. When PSEG LI assumed responsibility for long-range power supply planning in 2015, it began to develop a new IRP.[69] During the development of the IRP, PSEG LI conducted outreach with stakeholders to discuss the scope of the effort and to take input on scenarios and assumptions.[70]

- In order to ensure that LIPA's IRP reflected appropriate planning considerations, and adhered to industry norms in term of processes, methodologies and models, PSEG LI reviewed other utilities' IRPs and interviewed individuals involved in the development of the resource plans.[71]
    - PSEG LI reviewed 20 IRPs developed between 2011 and 2015 to benchmark the scope of other utilities' IRPs and the nature of each report's contents.[72]
    - PSEG LI also conducted telephone interviews with representatives of five utilities (Avista, Duke, PacifiCorp, PGE, Xcel, and NV Energy) to obtain a more in-depth understanding of the scope of the reports, key drivers, approach and issues.[73]

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[67] DR 155
[68] DR 715 Attachment 3
[69] DR 717 Attachment 1
[70] DR 717 Attachment 1
[71] DR 157
[72] DR 891
[73] DR 891

- LIPA's 2017 draft IRP has a 20-year planning horizon (2016 to 2035) with a 10-year actionable period (2016 to 2025). It looks at different scenarios and sensitivities to capture variations in load requirements and supply levels as well as assess overall system risk.[74] The detailed studies supporting the IRP take into account:

    - Production and capacity costs
    - Capital costs for new capacity and system improvements (as necessary)
    - Financial analysis
    - Fuel and load sensitivities
    - Regulatory requirements
    - Reliability needs
    - Environmental goals.[75]

- The 2017 draft IRP examines resource needs under various scenarios that address ongoing changes to the New York electric power industry, including:

    - Refor**ming the Energy Vision (REV)** – A NYS PSC framework to align markets and the regulatory landscape with the overarching state policy objectives of giving customers new opportunities for energy savings, local power generation, and enhanced reliability to provide safe, clean, and affordable electric service.[76]
    - **2015 State Energy Plan (SEP)** – Intended to coordinate all State agencies' efforts affecting energy policy to advance the REV agenda. In establishes NYS' 2030 goals for greenhouse gas emissions, energy efficiency, and renewable generation.[77]
    - **Clean Energy Standard (CES)** – An August 1, 2016 PSC Order that requires that 50 percent of New York's electricity come from renewable energy sources such as solar and wind by 2030, with a progressive phase-in schedule starting in 2017 (50 X 30).[78]
    - **State Resource Plan (SRP)** Study – NY DPS study to examine the impact of various public policies on the State's bulk power system.
    - **NYSERDA's Blueprint for Offshore Wind (OSW) Master Plan** – In January 2017, the Governor of New York announced a goal to develop 2,400 MWs of offshore wind by 2030.[79] The Master Plan will identify potential offshore wind sites that meet the State's siting standards and take into consideration environmental, maritime, economic, and social issues. The full Offshore Wind Master Plan was published in early 2018.[80]

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[74] DR 156

[75] DR 715 Attachment 20

[76] www.dps.ny.gov/REV/

[77] DR 715 Attachment 5

[78] https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard

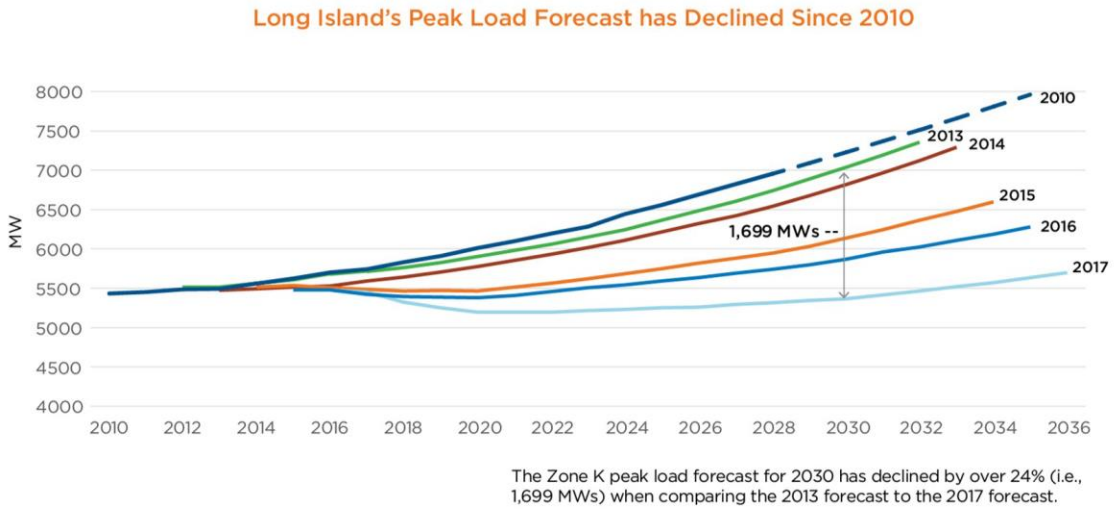
[79] DR 717 Attachment 1

[80] https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/New-York-Offshore-Wind-Master-Plan

16. **The 2017 draft IRP includes the impact of energy efficiency, rooftop solar, and other behind the meter renewables on LIPA's projected load forecast.**

- As shown in **Exhibit XIV-19,** current peak load forecasts are significant lower than previous forecasts. According to the IRP, the decrease in peak load forecast is driven by increases in energy efficiency, net metering, feed-in tariffs, the decoupling of economic growth and energy use, and lower economic growth projections.

Exhibit XIV-19
Zone K NYISO Peak Load Forecast



The Zone K peak load forecast for 2030 has declined by over 24% (i.e., 1,699 MWs) when comparing the 2013 forecast to the 2017 forecast.

Source: DR 717 Attachment 2.

- Long Island's peak load reductions are consistent with statewide and national trends and reflect significant and continuing changes in the energy markets.[81]
- Energy efficiency, rooftop solar, and other behind the meter renewables are expected to reduce LIPA's load by approximately 950 MW by 2030 (approximately 2,200 GWh).[82]
- The forecasted 2030 peak load is now about the same as the load was in 2016.[83]

17. **LIPA's planned power supply portfolio appropriately includes renewable energy sources.**

- On October 25, 2012, LIPA's Board issued a resolution to seek to add 400 MW of new renewable energy generation to its resource portfolio by 2018 through an expanded feed-in-tariff program and competitive procurement.[84]

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[81] DR 715 Attachment 3
[82] DR 715 Attachment 3
[83] DR 715 Attachment 3

  - The addition of 400 MW of new renewable generation was initially to be implemented through the issuance of the Solar FIT II, the Non-Solar FIT II and the 280 MW RFP. These procurements fell short of the 400 MW goal. Some of the selected projects did not move forward as they were improperly zoned or had community opposition, and the interconnection points for other proposed projects were saturated as a result of FIT I projects.[85]
  - In December 2015, when PSEG LI issued the 2015 renewable RFP it determined that 210 MW additional renewable capacity would be required to meet the 400 MW goal.[86]
  - In 2016, LIPA issued two additional FITs: FIT III – Commercial Solar and FIT IV – Fuel Cell.

- LIPA obtained an additional 90 MW renewable resources in response to the South Fork South Fork Resources RFP. The South Fork RFP was issued June 24, 2015, to meet peak load requirements at a load pocket on the South Fork of Long Island and did not solely target renewable projects. In fall 2016, PSEG LI selected four projects through its procurement process, including the 90 MW Deepwater off-shore wind project.[87]

- **Exhibit XIV-20** shows that as of November 28, 2017, LIPA had approximately 360 MW of active renewable projects in response to its Renewable RFPs and FITs. Approximately 33 MW of FIT solar projects are currently operating. The projected commercial operation dates for RFP-related projects range from March 1, 2018 to December 1, 2022 (Deepwater Off-Shore Wind).[88]

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[84] 2015 Renewable RFP 2016-05-17 Addendum No 5_clean.docx https://www.google.com/search?q=2015+Renewable+RFP+2016-05-17+Addendum+No+5_clean.docx&oq=2015+Renewable+RFO+2016-05-17+Addendum+No+5_clean.docx&aqs=chrome..69i57.1020j0j4&sourceid=chrome&ie=UTF-8

[85] IR 112

[86] 2015 Renewable RFP 2016-05-17 Addendum No 5_clean.docx https://www.google.com/search?q=2015+Renewable+RFP+2016-05-17+Addendum+No+5_clean.docx&oq=2015+Renewable+RFO+2016-05-17+Addendum+No+5_clean.docx&aqs=chrome..69i57.1020j0j4&sourceid=chrome&ie=UTF-8

[87] DR 540 Attachment 1

[88] 12/19/17 PSEG LI Power Procurement Presentation to the Oversight Committee of the Board of Trustees

Exhibit XIV-20
Status of Renewable RFPs and FITs as of November 28, 2017

Procurement	Date of Issuance	Status	Target Renewable Amount (MWs)	Active Project Amount (MW)
280 MW RFP	October 2013	Closed	280	66.4
South Fork	June 2015	Closed	0	90.0
2015 Renewables RFP	December 2015	Closed	210	58.9
FIT I - Solar	July 2012	Closed	50	39.3
FIT II - Solar	May 2014	Closed	100	41.2
FIT II - Non-Solar	May 2014	Closed	20	8.8
FIT III - Solar	July 2016	Open	20	16.8
FIT IV - Fuel Cell	July 2016	Open	40	39.8
Total			**720**	**361.2**

Source: DR 751 Attachment 1; 12/19/17 PSEG LI Power Procurement Presentation to the Oversight Committee of the Board of Trustees, NorthStar Analysis.

- As previously mentioned, on August 1, 2016, the NYS PSC issued an order requiring that 50 percent of the state's electricity must come from renewable sources by 2030, a "50 X 30" renewable energy benchmark. LIPA's IRP addresses the CES initiative.

  - LIPA's CES requirement is 12.3 percent of the statewide requirement of 29,000 GWh by 2030.
  - The IRP assumes that LIPA would meet its requirements by:

    - Acquisition of 400 MW of renewable resources by 2022.
    - Additional 400 MWs of utility scale renewables to comply with CES by 2030.
    - Small deficits in 2021 and 2029/30 are assumed to be met with banked credits.[89]
- The Governor's 2,400 MW offshore wind goal by 2030 will likely increase renewable generation interconnected to Long Island. NYSERDA had not released its Master Plan identifying potential offshore wind sites at the time LIPA issued its draft IRP, so specific interconnection considerations and potential wind-energy procurement are not addressed in the 2017 draft IRP.[90]

18. PSEG LI appropriately uses NYISO IRM and LCR planning criteria rather than the more conservative criteria used in LIPA's previous Electric Resource Plan Using the NYISO criteria, LIPA has excess generation capacity through 2035.

- The 2017 draft IRP uses NYISO IRM and LCR planning criteria, instead of the more conservative capacity planning criteria used in the 2010 Electric Resource Plan. The NYISO IRM and LCR planning criteria contribute to lower capacity requirements.

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[89] DR 715 Attachment 3

[90] DR 714 Attachment 3

  - Beginning in the early 2000's, LIPA applied more conservative island-specific reliability standards than other New York regions due to its geography and limited interconnection to adjacent power markets.
  - The 2017 IRP uses the NYISO IRM and LCR requirements for capacity adequacy as its planning criteria. Since the early 2000's Long Island has increased its connection to adjacent power markets through new transmission lines, and market mechanisms in NYISO have stabilized, so now LIPA can conduct its reliability planning process with increased certainty.

- In 2017, LIPA retained the Brattle Group to provide an independent second opinion on PSEG LI's reliability planning criteria. The Brattle Group found it is appropriate for LIPA to use the NYISO IRM and LCR requirements.[91]

- Using the NYISO criteria, with flat load growth and the addition of renewable generation to meet CES, LIPA has excess generation capacity through 2035[92]

19. **The current and planned use of the PSA units is effective and efficient. PSEG LI's studies show that the proposed repowering of the E.F. Barrett and Port Jefferson plants is not required.**

- In 2014, RCM Technologies, Inc. performed a high level condition assessment of the PSA units and determined that the units can reliably operate at least until the expiration of the PSA in 2028.

  - This conclusion was based on NG Generation's continuation of its capital and O&M program, its condition assessment program, and its root cause analysis program.
  - In 2016/2017 NG Generation confirmed that these programs were still in place.[93]

- As shown in **Exhibit XIV-21**, in 2016, the PSA units represented 63 percent of LIPA's generation capacity, while generating only 22 percent of energy requirements.

  - The NYISO determines which units run to optimize and reduce costs.
  - The PSA steam unit usage has declined since the late 1990s as a result of the addition of more efficient on-island generation and contracts with CSC and Neptune transmission cables that connect Long Island to the PJM and NE-ISO power markets.
  - The PSA steam units operate reliably with equivalent availability (summer) averaging above 90 percent, in line with more modern LIPA-contracted combined cycle facilities.[94]

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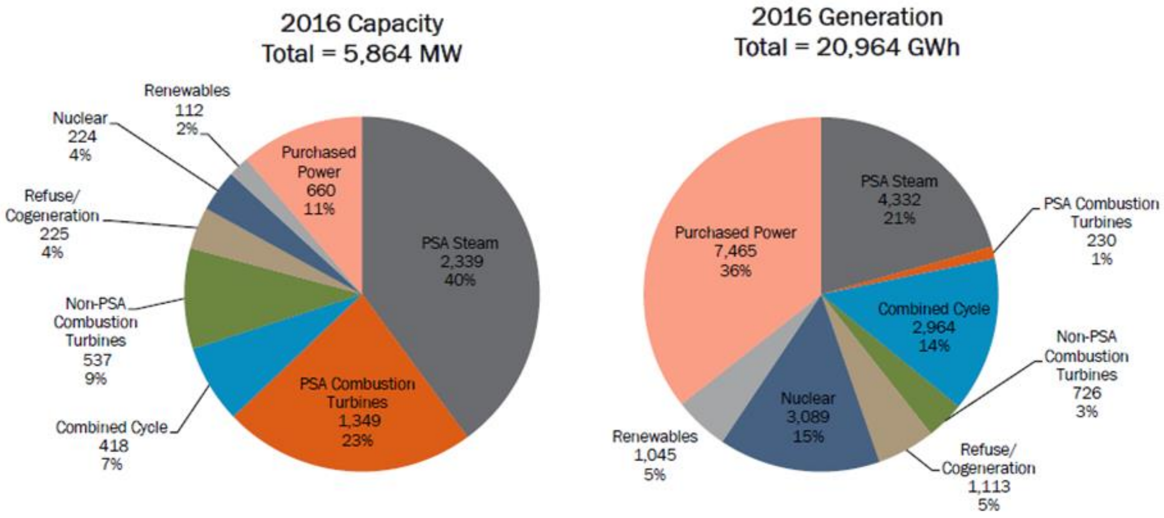
[91] DR 715 Attachment 2

[92] DR 282 Attachment 1

[93] DR 715 Attachment 21

[94] DR 715 Attachment 3

Exhibit XIV-21
2016 LIPA Generation and Capacity by Resource Type



Source: DR 715 Attachment 3.

- As part of its IRP analysis, PSEG LI evaluated three proposals to build combined cycle plants on Long Island.
  - In June 2015, the NYS Legislature enacted an amendment to the LIPA Reform Act that required LIPA and PSEG LI to conduct feasibility studies of repowering three PSA steam plants, as shown in Exhibit XIV-22.

Exhibit XIV-22
Required PSA Unit Repowering Studies

PSA Steam Units:	Capacity (MW)	Facility Type	Fuel	Study Due Date
Northport 1, 2, 3, 4	1,552	ST	Gas, Residual Oil	April 2020
E.F. Barrett 1, 2	385	ST	Gas, Residual Oil	April 2017
Port Jefferson 3, 4	383	ST	Gas, Residual Oil	April 2017

Source: DR 717 Attachment 1.

  - The E.F. Barrett and Port Jefferson plant repowering studies are part of the April 2017 draft IRP package. The Barrett repowering proposal is a 637 MW project that would replace the Barrett steam units and most of the on-site combustion turbines. The Port Jefferson repowering proposal is a 397 MW project that would replace the Port Jefferson steam units.[95]
  - In its IRP analyses, PSEG LI also re-examined the need for and cost effectiveness of the proposed 706 MW Caithness II combined-cycle power plant.[96] This project

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[95] DR 715 Attachment 3 4/10/2017 PSEG IRP Summary Report

[96] DR 717 Attachment 1

was proposed in response to a 2010 RFP. Contract negotiations had been suspended in 2014, pending the completion of the IRP.[97]

- The studies showed that replacing the E.F. Barrett and Port Jefferson steam plants with combined-cycle plants and the proposed Caithness II plant are not needed for reliability or economic purposes.

  - In aggregate, the proposed combined-cycle plants would impose a substantial net cost increase of approximately $5 billion, after consideration of the savings in fuel, capacity, and the avoided fixed and variable costs of the existing steam plants.
  - Compliance with CES and the addition of substantial amounts of offshore wind resources will cause a significant decline in the energy production of the steam plants, as well as any replacement plants, further eroding the economics of repowering.

- The 2017 draft IRP points out that the proposed combined cycle plants have operating characteristics that are more flexible than the PSA steam units, but less flexible than typical peaking units and that peaking units may better balance intermittent renewable resources.[98]

- LIPA retained the Brattle Group to provide an independent second opinion on PSEG LI's reliability planning criteria, Caithness II, and the repowered steam plants. The Brattle Group found that there is no compelling reason for LIPA to proceed with the combined cycle plants.[99]

20. PSEG LI does not benchmark its power supply activities with other utilities, but it does obtain a perspective on industry supply procurement practices through its use of outside consultants. This is adequate in light of the fact that the power supply pricing and performance data are typically considered confidential and PSEG LI's supply procurement efforts are focused on renewable energy, a market which is still evolving.

- PSEG LI does not benchmark its power supply procurement performance with other utilities.[100]

- The pertinent provisions of most PPAs (such as pricing and performance guarantees) are confidential and not shared.

- PSEG LI obtains a perspective on industry practices through its use of outside technical and legal consultants as part of its power supply procurement process.

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[97] DR 715 Attachment 3

[98] DR 715 Attachment 3 Draft 2017 RFP

[99] DR 715 Attachment 8

[100] DR 750

  - The consultants provide expertise in areas such as the quantitative and qualitative evaluation of proposals, as well as contract negotiations including terms, conditions, price and performance guarantees.
  - Since these outside consultants have performed similar work for other clients they therefore bring their expertise and industry knowledge to bear without violating confidentiality agreements.[101]

- As discussed in Conclusion 18, the LIPA's draft 2017 IRP shows that it has sufficient generation capacity through 2035. PSEG LI's supply procurement efforts are focused on obtaining renewable energy through feed-in-tariffs and RFPs.

21. LIPA has a defined and disciplined approach for its power supply and fuel hedging hedge plan that is effective.

- In accordance with the PSMA, PSEG ER&T executes LIPA's commodity derivative and hedging program, and retains an independent consultant to provide hedge advisory services. PSEG ER&T manages the process pursuant to a Policy on Power Supply Hedging and Policies and Procedures, which includes a description of LIPA's hedge plan.[102]

- The goal of LIPA's Hedge Plan is to mitigate a portion of the volatility of LIPA's energy supply costs. The Hedge Plan addresses the following energy commodities:

  - Natural Gas Henry Hub
  - Transco Zone 6 Basis (gas)
  - Iroquois Zone 2 Basis (gas)
  - PJM West Hub On-Peak, Off-peak and Around-The-Clock (ATC)
  - Jersey Central Power and Light On-Peak, Off-Peak and ATC
  - PJM West Hub to Jersey Central Power and Light On-Peak, Off-Peak and ATC basis.[103]

- The Hedge Plan is based on a methodological approach that outlines a strategy of hedge positions between 45 and 80 percent of the required amounts for a timeframe, three years out beyond the current calendar year. It is based on an objective procurement methodology, developed by LIPA's hedge advisor, INTL FC Stone, that bases a commodity's value on comparing historical price distribution of various futures contracts. Positions are executed based on either time or price triggers

  - Value Price Triggers –Value price triggers are determined for each commodity for a specified period using four-year historical price data.
  - Time Triggers – If value price triggers do not meet the minimum hedge volume requirement by a specified date, Time Triggers are used.
  - Catastrophic Price Triggers – Protect price spikes with options when the market price is at a specified price level.[104]

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[101] DR 750

[102] DR 141

[103] DR 288 Attachment 1

- The Hedge Plan specifies the hedge instruments that may be used for value and time triggers and that are tied to defined price levels.[105]

- PSEG ER&T's execution of hedge transactions is programmatic, and outlined in a detailed procedure. Traders receive a daily report that indicates the need to execute hedge transactions.[106]

22. The hedge plan also addresses counterparty credit risk.

- The goal of the credit risk management process is to:
    - Protect LIPA against any unwarranted counterparty credit exposures.
    - Maintain credit risk at a level acceptable to LIPA.
    - Identify and avoid credit failures that could have a financial impact on LIPA.

- To minimize the potential adverse financial impact to the PSC from a defaulting counterparty, LIPA's Hedge Program will not permit transactions with counterparties that have "below investment grade" credit ratings from S&P, Moody's or Fitch. Limited exceptions to this policy are outlined in the LIPA Policies, Controls and Procedures Manual for the Power Supply Hedging Program.[107]

- The Middle Office performs the counterparty credit risk management function on behalf of the ERMC.
    - The Middle Office performs an initial evaluation of the creditworthiness of a potential counterparty using the appropriate scorecard within the Credit Scoring Model.
    - Once the credit evaluation is complete and the appropriate agreement has been fully executed, the company is placed in the LIPA credit portfolio.
    - On a daily basis, the Middle Office monitors counter parties' credit worthiness by looking at daily news summary that includes rating agency updates as well as Bloomberg, Reuters, Yahoo Finance and Business Wire news items.
    - On a quarterly basis, the Middle Office uses the Credit Scoring Model to update its rating of each counterparty when that counterparty's financial statements become available.[108]

23. LIPA's power supply hedge program meets it objective of reducing the volatility of energy supply prices.

- As stated in the Board's power supply hedging policy, LIPA's primary hedging program objective is to reduce customers' exposure to significant PSC volatility.[109]

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[104] DR 288 Attachment 1.

[105] DR 671 Attachment 2

[106] DR 287

[107] DR 288 Attachment 1

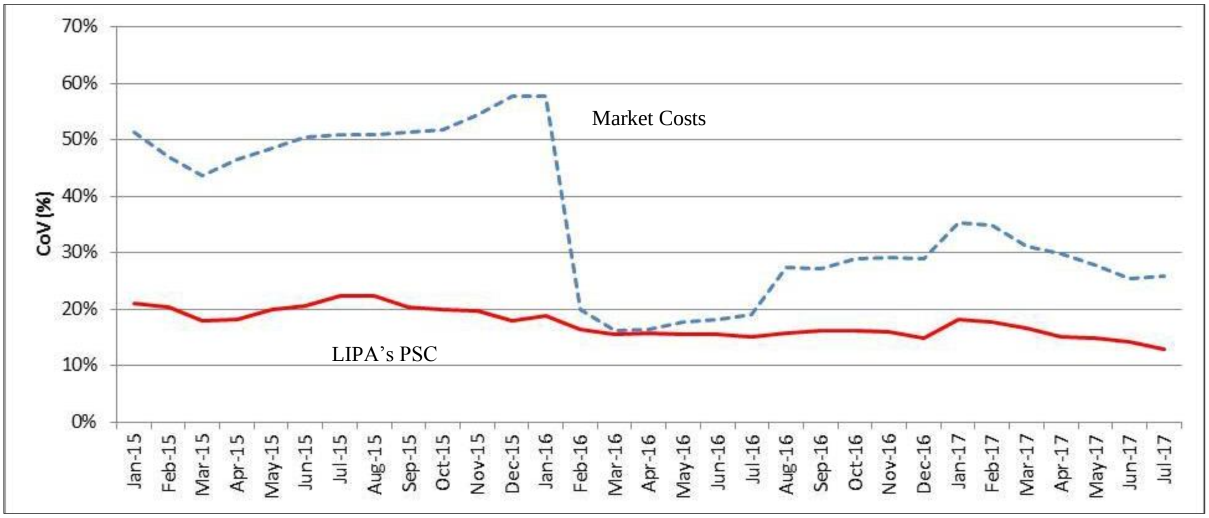
[108] DR 288 Attachment 1.

[109] DR 288 Attachment 1

- **Exhibit XIV-23** compares the volatility of LIPA's PSC (which includes the impact of hedging) to volatility of NYISO market prices, and shows that the hedge program reduced the volatility of energy supply prices

  - LIPA's PSC costs include the impact of hedging, and show less variation than the un-hedged market costs.
  - Price volatility is represented by the rolling 12-month coefficient of variation, which shows the variation of the standard deviation from the average market settle price of the previous 12-month period.
  - Market costs include energy, capacity, transmission and auxiliary services.

Exhibit XIV-23
Price Volatility [Note 1] - LIPA PSC vs. Market Prices



Note 1: Volatility is represented by the 12-month rolling coefficient of variation.
Source: September 27, 2017 Board Materials, PSEG Power and Fuel Management. DR 906 Attachment 10.

24. LIPA exercises appropriate oversight over its power supply hedging program.

- LIPA's power supply hedging activities are governed by a formal policy adopted by its Board on August 6, 2014 which designates LIPA's ERMC as the controlling authority with respect to the power supply hedging program.

  - The ERMC provides executive management oversight for LIPA's energy risk management activities and monitoring of its program metrics.
  - The ERMC generally meets on a monthly basis.[110]

- The ERMC is chaired by LIPA's CFO, who is charged with Chief Risk Officer responsibilities. Other LIPA senior management personnel serve on the ERMC,

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[110] DR 288 Attachment 1

including the CEO, VP of Financial Oversight, the Director of Risk Management and members of the Operations Oversight and Finance teams.[111]

- PSEG's Chief Risk Officer oversees the Middle Office function and is a non-voting ex-officio member of the ERMC.

- With assistance from an independent consultant, INTL FC Stone, PSEG ER&T's Middle Office provides support to the ERMC, including:

  - Providing an overview market conditions and an assessment of LIPA's current energy portfolio and hedging positions in context of those conditions at each ERMC meeting.
  - Providing support regarding key decisions.
  - Notifying the ERMC promptly of any known violations of the Hedge Plan.
  - Periodically reviewing the power supply hedging manual and recommending changes to enhance its effectiveness.
  - Compiling a list of known counterparties and their respective credit restrictions.
  - Preparation of periodic reports.[112]

- In order to maintain proper separation of duties, the Middle Office is not authorized to execute energy trading or energy risk management transactions with counterparties on LIPA's behalf.

25. LIPA and PSEG ER&T perform a benchmark review of the power supply hedge program on a quarterly basis.

- The Middle Office and INTL FC Stone developed a benchmark program to evaluate current program parameters to determine what and where improvements might be called for, and to use this information to adjust future program parameters.[113]

- INTL FC Stone performs a quarterly benchmark analysis for each energy commodity (such as Natural Gas Henry Hub and reviews the results with the ERMC.[114]

- **Exhibit XIV-24** lists LIPA's hedge program quarterly benchmarks.

Exhibit XIV-24
Hedge Program Quarterly Benchmark Comparisons

Benchmark	Description
Index Comparison	Compares hedge/blended price to market price. Illustrates the differential of hedge costs to "default" settlement prices.
Look-Back Settled	Compares hedge/blended price to the historical price distribution. Evaluates where *settled* hedges fall within historical price quartiles of forward prices.

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[111] DR 141
[112] DR 288 Attachment 1
[113] DR 288 Attachment 1
[114] DR 906

Benchmark	Description
Look-Back Open	Compares hedge/blended price to the historical price distribution. Evaluates where *open* hedges fall within historical price quartiles of forward prices.
Volatility Comparison	Compares hedge price volatility to market price volatility over 12-month period. Measures the level of price volatility reduction.
Methodology Review	Snapshot of hedge triggers executed to date overlaid on hedge price horizon. Measures LIPA's adherence to established hedge plan triggers and a snapshot of "How Are We Doing" versus the market.

Source: DR 288 Attachment 1.

26. LIPA appropriately compares its power supply hedge program to other utilities' and modifies its program to be in line with industry best practices.

- LIPA's Hedge Advisor, INTL FC Stone performs an annual survey of industry hedge components. Over 20 North American utility companies participate in the Survey.[i]

- **Exhibit XIV-25** lists the annual survey topics.

Exhibit XIV-25
Hedge Program Quarterly Benchmarks

Survey Topic	Example Responses
Objectives of hedge plan	Volatility reduction, budget protection
Hedge strategy methodologies	Historic pricing, time-based programmatic, technical analysis
Hedge horizon	Three years
Hedge volume	Percent of commodity purchases hedged
Instruments	Physical, calls, options
Seasonal and Basis Hedging (New for 2017)	Hedge both seasons, or only in one winter, whether they have pipeline or storage capacity
Catastrophic price protection above minimum volumes (New for 2017)	Exceed the minimum volume requirement if prices stay above value limits

Source: DR 671 Attachment 2.

- As a result of the 2017 annual survey, LIPA changed the maximum position specified in its hedge plan from 75 percent to 80 percent to be in line with other utilities.[115]

27. LIPA has grandfathered Transmission Congestion Contracts (TCCs) which hedge for congestion associated with off-island imports.

- LIPA retains a portfolio of grandfathered TCCs that it received upon NYISO inception in exchange for physical rights associated with its existing transmission contracts.[116]

- LIPA purchases nearly all of its off-island power supply over transmission paths that are covered by TCCs. These TCC rights hedge LIPA for congestion and mean that

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[115] DR 671 Attachments 1and 2

[116] DR 326

those imports can be purchased at the spot price of power in the connecting area with no additional import charge.[117] Much of the remainder is hedged with long-term contracts with generating resources.[118]

- As LIPA has the grandfathered TCC's, it does not participate in the TCC or FTR auctions administered by the ISO markets.[119]

E. LIPA'S FUEL AND PURCHASED POWER COST RECOVERY

Evaluative Criteria

- Is LIPA's PSC Tariff clear, useful and comprehensive? (Conclusions 28 and 29)
- Are the items listed under Tariff Leaf 166 reasonable, and are they related to fuel and purchased power costs?
- Has LIPA implemented its fuel and purchased power tariff in compliance with the requirements specified in the tariff?
- Are changes necessary to LIPA's Tariff Leaf 166 to better describe and illustrate actual fuel and purchased power costs?
- Are the costs included in LIPA's clause (PSC, previously known as FPPCA) recovered exclusively through that clause, or are they also included in other rates and charges?
- Do the actual costs recovered correctly reflect what is allowed under Tariff Leaf 166?
- Are the charges recovered through the PSC approved by the appropriate managers and Authority's Board of Trustees?
- Does LIPA maintain sufficient historical financial records for a reasonable time frame to assist with the verification of fuel and purchased power cost?
- Are the projections of future fuel costs incorporated in the PSC reasonable?
- Are there possible improvements to LIPA's fuel and purchased power cost reconciliation with customer bills?
- Does PSEG LI have effective policies, procedures, and processes for determining the correct cost recovery amounts, approving changes to cost recovery, and verifying cost recovery under the adjustment clause?

Findings and Conclusions

28. As a result of the modifications to the PSC tariff adopted by the Board on December 20, 2016, all power supply costs are recovered exclusively through the PSC. This improves the clarity of the tariff and provides better cost signals to customers.

- Changes to the PSC tariff must be approved by LIPA's Board, and are subject to the provision of the State Administrative Procedure Act, which specifies various requirements for public notice, including public meetings in Nassau and Suffolk Counties.

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[117] Brattle Report
[118] DR 326
[119] DR 287

- Since the last management audit, the Board has approved three changes to the PSC tariff, all effective January 1, 2017. These changes are summarized in **Exhibit XIV-26**.

Exhibit XIV-26
Changes to FPPCA (PSC) Tariff Effective January 1, 2017

Change	NorthStar Comments
1. Transferring the operating expenses and taxes related to power supply into the Power Supply Charge (PSC)	Eliminated fuel and purchased power costs from the delivery charge. Prior this this, the delivery charge included the following: - PSA costs for the legacy power plants on Long Island. - O&M and property taxes of LIPA's 18 percent ownership share in the NMP2 nuclear power station. - Property taxes paid by LIPA on behalf of certain merchant power plants under contract to LIPA on Long Island. The transfer of the power supply costs from the Delivery Charge to the PSC eliminated the need for the Recharge New York Delivery discount.
2. Adopting the term "Power Supply Charge" within the Tariff.	The term "Power Supply Charge" is what customers see on their bills and in PSEG LI communications.
3. Recognizing the costs for compliance with the Clean Energy Standard in the PSC.	The PSC already included the recovery of costs for renewable energy purchases and costs incurred under the NY Renewable Portfolio Standard (RPS). In 2016, the NYS PSC replaced the RPS with a successor program, the Clean Energy Standard (CES). This change to the tariff clarifies that the replacement program is also recoverable through the PSC. [Note 1]

Note 1: Costs incurred for CES compliance that were already recoverable under the Distributed Energy Resources (DER) rider, such as energy efficiency costs, continue to be recovered under the DER rider rather than under the PSC.
Source: DR 190 Attachment 1.

- NorthStar's review of the components of the Distributed Energy Resources (DER) Cost Recovery rate confirmed that DER costs are not included in the PSC.
  - The DER recovers the cost of expenditures on distributed energy resource programs explicitly approved by the LIPA BOT for the coming year.[120]
  - The 2016 and 2017 DER rate components were the costs of LIPA's energy efficiency programs and the Residential Energy Affordability Partnership.[121]

29. LIPA PSC Tariff is clear, useful and comprehensive and specifies reasonable items as power supply costs. The actual costs recovered through the PSC correctly reflect what is allowed under Tariff Leaf 166.

- The current categories of costs included as fuel and purchased power costs specified in the PSC tariff are listed in **Exhibit XIV-27**.

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[120] http://www.lipower.org/pdfs/company/tariff/LIPA%20Tariff%20June%201%202017.pdf. Third Revised Leaf No. 182A

[121] DR 927

Exhibit XIV-27
Categories of Fuel and Purchased Power Costs in the PSC Tariff (Leaf 166)

Category	Costs
Fuel and Purchased Power Costs	• Purchased fossil fuel • Nuclear fuel purchased for NMP2 • NMP2 nuclear fuel disposal, decontamination and decommissioning costs • Costs incurred for the operation, maintenance, and property taxes of the Authority's share of the NMP2 generating facility • Power purchased from NYPA, National Grid, other utilities, IPPs, QFs and customer generators, including property taxes • Costs incurred under any PSMA or FMA • Costs to comply with the requirements of the NYS Renewable Portfolio Standards and the purchase of renewable energy credits (including the cost of any alternative compliance payments) and zero emission credits associated with the New York Clean Energy Standards programs • 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

Note 1: LIPA does not sell energy off-system, so this category is not used.
Source: Leaf 166 FPPCA Tariff effective January 1, 2017.

- NorthStar's detailed testing of the costs and revenues included in PSC calculations confirmed all line items were related to costs and revenues specified in the tariff.[122]

30. In order to better reflect the seasonality of capacity requirements and to stabilize the monthly PSC rate, LIPA changed its treatment of fixed capacity costs in the PSC calculation.

- In December 2015, the Board approved implementation of a PSEG LI recommendation regarding treatment of capacity costs in the monthly PSC calculation.[123] Until that time, the PSC included equal monthly costs for capacity purchased from third parties, as billed under the purchase agreements. With the revised treatment of capacity costs, LIPA recovers these costs on a seasonal basis. [124]

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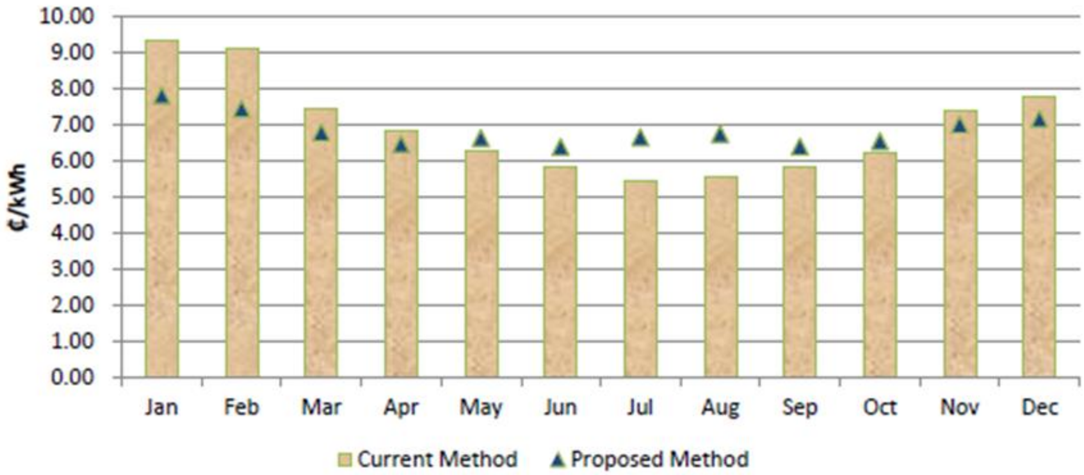
[122] DR 675 and 676
[123] DR 14 Attachment 162
[124] DR 14 Attachment 162

  - Through the PSC, LIPA recovers approximately $420 million per year for third-party capacity costs, of which approximately $395 million are fixed costs under existing power and transmission purchase agreements. These costs are charged to LIPA in essentially equal payments each month. However, these costs are incurred primarily to meet capacity requirements in the peak summer months.
  - PSEG LI recommended that LIPA's rates should reflect greater cost responsibility in the summer months as opposed to the winter months.
  - To implement this proposal, LIPA created a regulatory asset to defer recovery of capacity costs in the PSC during the winter months of November through April, and to amortize their recovery in the summer months of May through October.[125]

- The net annual impact of the deferral and amortization of capacity costs is zero. The PSC continues to adjust to recover LIPA's actual fuel and purchased power costs on a monthly basis within each calendar year. [126]

- The higher capacity costs included the summer PSC calculation are offset by the generally lower cost of natural gas in summer months.[127] As a result, there is lower volatility in the month-to-month PSC rates, as shown in **Exhibit XIV-28**, a projection presented to the Board in December 2015 when it was considering changing the treatment of capacity costs.

Exhibit XIV-28
Projected 2016 PSC Rate with Seasonal Treatment of Capacity Costs



Source: DR 14 Attachment 169.

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[125] DR 14 Attachment 162
[126] DR 14 Attachment 162
[127] DR 14 Attachment 162

31. PSEG LI has effective policies, procedures, and processes for determining the correct cost recovery amounts and verifying cost recovery under the adjustment clause.

- PSEG LI's Power Markets Department is responsible for the development of the monthly PSC rate.[128]

- PSEG LI calculates the PSC 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. The PSC is calculated by dividing the projected month's cost of fuel and purchased power costs and LI Choice bill credits by the projected month's energy sales, as shown below.

$$\textbf{Month } \textbf{3}\text{ PSC Rate} = \frac{\begin{array}{c}\textbf{Month 1}\\ \textbf{Actual}\text{ Amount}\\ \text{Under/Over-Collected}\\ (\$)\end{array} + \begin{array}{c}\textbf{Month 2}\\ \textbf{Projected}\text{ Amount}\\ \text{Under/Over-Collected}\\ (\$)\end{array} + \begin{array}{c}\textbf{Month 3}\\ \textbf{Projected}\\ \text{F\&PP Costs}\\ (\$)\end{array} + \begin{array}{c}\text{Other}\\ \text{Adjustments}\\ (\$)\end{array}}{\text{Month 3 Projected Sales (GWh)}}$$

Source: NorthStar Analysis of DR 194.

- An overview of the inputs to the PSC calculation is shown in **Exhibit XIV-29**.

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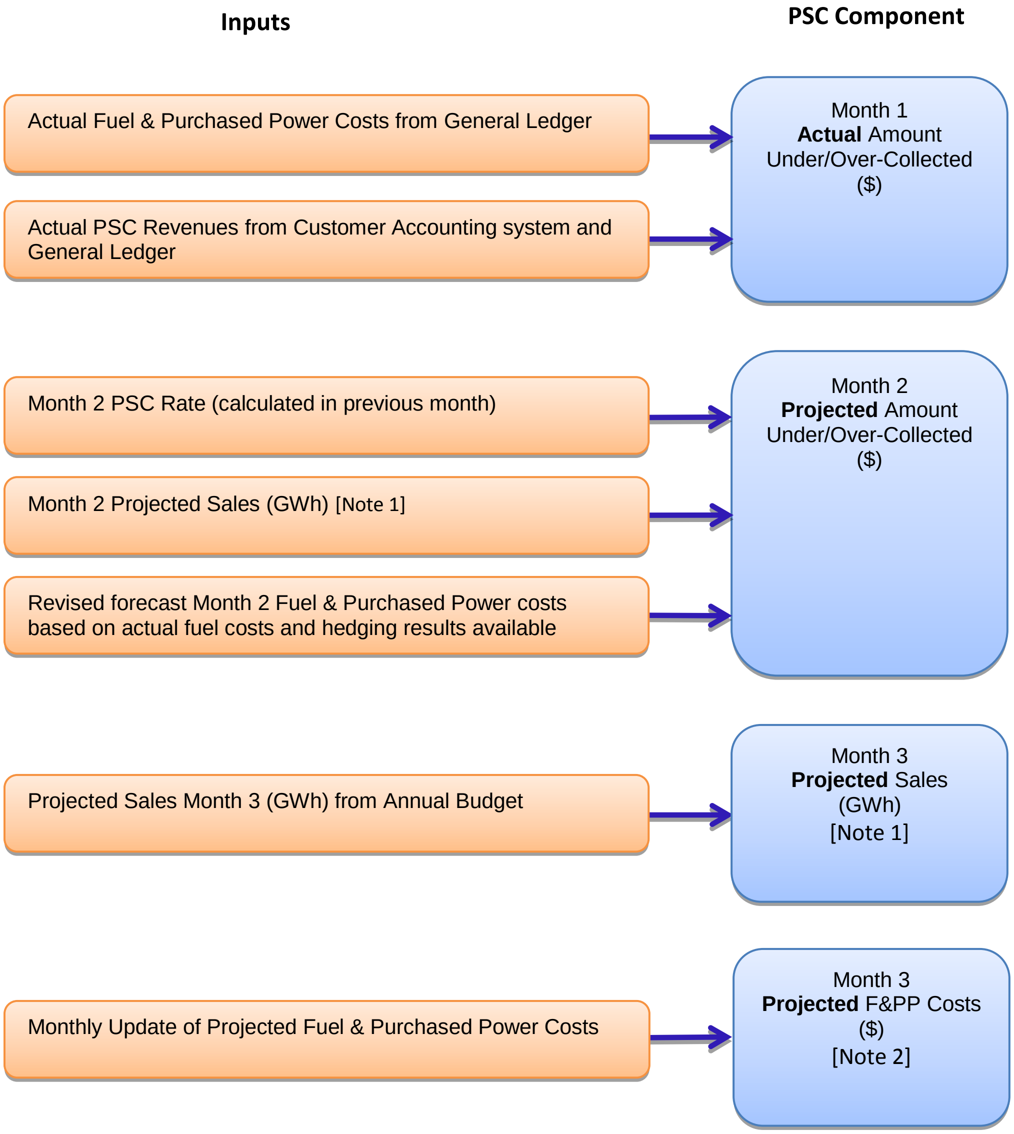
[128] DR 159

Exhibit XIV-29
Inputs to Monthly PSC Calculation
(PSC Calculation is for Month 3)



Note 1: Sales are adjusted for BNL Service, LI Choice service, and Recharge NY.
Note 2: F&PP costs are adjusted for the BNL expenses
Source: DR 194, NorthStar Analysis.

- PSEG LI's process to calculate the monthly PSC rate is documented in a formal procedure, Fuel & Purchased Power Adjustment Internal Control Narrative dated November 11, 2016.[129]

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[129] DR 159 Attachment 2

- PSEG LI forwards the PSC rate and supporting work papers to LIPA for its review. Once LIPA has completed its review, Power Markets' Manager of Planning and Analysis sends the PSC rate to PSEG LI communications and authorizes the release of the PSC Rate to Finance/Pricing, Rates and Load.[130]

32. PSEG LI uses reasonable projections of fuel and purchased power costs in the PSC and uses Customer Accounting System data to accurately determine PSC over-and under-collections.

- PSEG LI's Power Markets' Planning and Analysis group calculates the PSC rate based on both actual and projected expenditures and recovery of the eligible costs. Input data other than projected sales are updated monthly. Projected sales for the upcoming month are based on the annual sales forecast in LIPA's approved budget unless LIPA approves, over the course of the year, an update to the level of forecasted sales used in the approved budget.
- **Exhibit XIV-30** lists the monthly data updates used in the PSC calculation.

Exhibit XIV-30
Monthly Data Updates Used in PSC Calculation
(Calculation is for Month 3)

Data Source	Data	PSC Calculation Component
Actuals for Month 1		
Finance Department/Rates and Pricing	Fuel Revenue reported in Customer Accounting System (CAS).	Used by General Accounting to determine PSC deferral balance (under/over-collection)
PSEG LI Finance Department/General Accounting:	PSEG LI general ledger month-end balance for fuel and purchased power expenses.	
LIPA General Accounting	Final actual month end balance recorded on LIPA books for fuel and purchased power expenses.	
PSEG LI Finance Department/General Accounting	PSEG LI year-to-date PSC Deferral balance recorded in general ledger.	Month 1 Actual Amount Under/Over-Collected ($)
Actuals and Projections for Month 2		
PSEG ER&T	Actual and expected hedge expenses and financial settlements as well as projections of fuel prices to be used in PSEG LI Power Markets - Planning and Analysis' calculation of the PSC.	Month 2 Projected Amount Under/Over-Collected ($)
PSEG ER&T/Fuel Supply Management	Natural gas expense for the current month as of the time reported.	Revised forecast Month 2 Fuel & Purchased Power costs
PSEG ER&T/Gas Trading	Oil expense for the current month as of the time reported.	
PSEG LI Power Markets - Planning and Analysis	Forecast of expected sales for Month 2.	Month 2 Projected Amount Under/Over-Collected ($)

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[130] DR 159 Attachment 2

Data Source	Data	PSC Calculation Component
Projections for Month 3		
PSEG ER&T	Projected fuel prices (gas and oil) for Month 3 and estimated hedge expenses and financial settlements.	Used by Power Markets Strategy and Planning for MAPS runs.
PSEG LI Power Markets - Strategy and Planning	Projected production costs (fuel and purchased power expenses) based on MAPs modeling.	Month 3 Projected PSC Costs ($)
Monthly PSC Rate Input into CAS for Customer Bills		
Finance Department/Rates and Pricing	Provides the PSC rate as calculated by Power Markets, to the Third-Party Billing and Support Department. Validates the rates are properly loaded into CAS.	
Third Party Customer Billing	Inputs PSC rate into CAS.	

Source: DR 159 Attachment 2, DR 674.

- Power Markets' Strategy and Planning group projects the fuel and purchased power expenses for the upcoming month (Month 3) using MAPS (Multi-Area Production Simulation), a production simulation model.
  - PSEG ER&T, responsible for LIPA's fuel supply, provides projected oil and gas prices for the upcoming month.
  - The Strategy and Planning group incorporates the updated commodity prices in 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. If necessary, projections are modified to reflect changes in the actual or expected configuration of the generation and transmission system such as major cable and/or generator unit outages.[131]

- PSEG ER&T provides Power Markets Strategy and Planning with available updates for: hedging expense and financial settlements; Natural Gas and Fuel Oil expense. These data are used to refine the projected F&PP costs for the current month (Month 2).[132]

- PSEG LI's Finance/General Accounting organization compiles the year-to-date fuel and purchased power recovery revenue received from customers, as well as the fuel and purchased power costs incurred.
  - PSEG LI's Rates and Pricing group provides customer fuel revenue data.
  - PSEG LI and LIPA's Accounting Departments each maintain separate general ledger accounts to record the Fuel and Purchased Power Costs as defined in Section VII.A. of LIPA's Tariff.

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[131] DR 159 Attachment 2

[132] DR 159 Attachment 2

- PSEG LI and LIPA have been assigned specific costs to record on their respective books to ensure costs are not recorded on both PSEG LI and LIPA's books.[133]

33. The PSC charge is correctly reflected on customer bills.

- As shown in **Exhibit XIV-30**, after Power Markets determines the PSC rate, the PSEG LI Finance Department/Rates and Pricing provides the PSC rate as calculated by Power Markets, to the Third-Party Billing and Support Department and validates the rates are properly loaded into CAS.

- In accordance with the Tariff requirement that LIPA prepare and retain on file a Statement of the Power Supply Charge, and make that Statement available at its business offices, LIPA posts the monthly Statement of the Power Supply Charge on its website.

- As discussed in **Chapter XI – Customer Operations,** NorthStar verified that the PSC charge is properly reflected on customer bills, prorated across months of energy usage.

34. LIPA maintains sufficient historical financial records to assist with the verification of fuel and purchased power cost in the audit period.

- LIPA and PSEG LI retain their records pursuant to the Records Retention and Disposition Schedule MI-1, issued by NYS Education Department. The retention schedule specifies a 6-year retention period for journal entries, invoices and purchase orders, and customer billing records.[134]

- LIPA was able to provide NorthStar with all requested documentation for NorthStar's detailed transaction testing.[135]

F. RECOMMENDATIONS

1. Memorialize the process regarding PSEG LI conflict of interest in regional market activities (discussed in Section 4.18 of the A&R OSA) in the Contract Administration Manual (CAM).

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[133] DR 159 Attachment 2
[134] DR 160 and 526
[135] DR 675 and 676

XV. PENSION AND OPEB INVESTMENTS

This chapter provides NorthStar's review and assessment of LIPA's management of investments for Pension and Other Post-Employment Benefits (OPEB).

A. BACKGROUND

Pension and OPEB Investments

LIPA is responsible for pensions and OPEBs for two groups of employees: PSEG LI (referred to as SERVCO) employees and full-time LIPA employees. Neither LIPA nor PSEG LI has responsibility for current or former National Grid Employees who are not currently employees of LIPA or PSEG LI.[1]

PSEG LI employees are covered by a defined benefit retirement program and a combination of OPEB programs. Public Service Enterprise Group (PSEG) manages the pension investments in trust through the SERVCO Thrift and Pension Investment Committee, which is overseen by the PSEG Thrift and Pension Investment Committee. The costs of the benefit programs for SERVCO employees are a "pass through expenditure" to LIPA (as defined in the OSA) ultimately payable by LIPA.[2] The pension funds for PSEG LI employees are kept in a Trust that is separate from that of other PSEG, Public Service Electric & Gas (PSE&G) and affiliates employees.[3] Members of PSEG LI management participate in the same fund as PSE&G (New Jersey) employees, not the one managed by the SERVCO Committee. LIPA deposits the necessary funds for the OPEB in PSEG LI's three-month operating account and PSEG LI pays the appropriate amounts to PSEG for deposit in the Pension Trust.

All full-time LIPA employees participate in one of two employee retirement plans offered by LIPA, discussed in **Exhibit XV-1**. All full time employees are eligible to participate in the Retirement System define benefit program. Full time employees whose compensation is $75,000 per year or higher may elect to participate in the NYS Voluntary Define Contribution Plan instead of the Retirement System.

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[1] DR 264, 265, 275

[2] DR 275 Attachment 1, Consolidated Annual Financial Report for December 31, 2016, Note 13 (p. 65) and Note 14

[3] DR 267, 268

Exhibit XV-1
LIPA Employee Pension Plans

Plan	Description	Fund
NYS Local Retirement System (the Retirement System)	The Retirement System is a multiple-employer defined benefit retirement system.	Funds for the employees in this plan are paid by LIPA based on actuarial studies by, and held in, the New York State Common Retirement Fund (the Fund). The Comptroller of the State of New York serves as the trustee of the Fund and is the administrative head of the Retirement System.
NYS Voluntary Defined Contribution Plan (VDCP)	The employee picks investments and providers for their contributions from the choices offered.	LIPA contributes 8 percent of the employees' salary to the trustee at the time the bi-weekly payroll is processed. The investment choices offered are determined by the contracted administrator Teachers Insurance and Annuity Association of America and College Retirement Equities Fund (TIAA CREF).

Source: DR 268, https://www.tiaa.org/public/ms/nyvdc/employee.html.

LIPA pays for post-retirement health plans (part of OPEB) for employees of LIPA on a pay-as-you-go basis. These funds are not held in a trust, but they are invested by LIPA. The amounts invested each year are based on an actuarial analysis and the entire amount, including funds held for future use, are considered expenses in the current year.[4]

LIPA pays for OPEB for employees of SERVCO based on based on actual expenses through the three month funding requests. These assets are set aside in a dedicated reserve account, not a trust, to meet this liability as expenses are incurred.[5]

B. EVALUATIVE CRITERIA

- Review and evaluate the Authority's pension and OPEB policies and procedures used in the management of its Pension and OPEB trust funds.
- Evaluate the asset allocation of the Pension and OPEB trust funds to ensure the proper investment mix between asset classes.
- Review and evaluate the fund manager selection process used by the Authority.
- Review and evaluate the existing fund managers that are managing the assets of both funds.
- Determine if funds associated with LIPA employees are managed by each trust in a manner consistent with the funds of other employees managed by the same trust.

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[4] DR 274 Attachment 1
[5] DR 274 Attachment 2

C. FINDINGS AND CONCLUSIONS

Because this analysis covers two different organizations for two different groups of employees, the Findings and Conclusions are presented in two sections, LIPA and PSEG LI.

LIPA

1. **Pension trust funds for LIPA employees are managed by the Retirement System or by the NYS Voluntary Defined Contribution Plan (VDCP). The Authority does not manage the pension trust funds and therefore does not have any policies and procedures related to the management of pension funds.**

   - Both the Retirement System and VDCP are professionally managed and are administered by the Office of the State of New York Comptroller. The Comptroller of the State of New York serves as the trustee and is the administrative head of the Retirement System. These funds provide benefits for thousands of current and former employees of the State of New York as well as other state entities.

   - System benefits for the defined benefit plan are established under the provisions of the New York State Retirement and Social Security Law. Participants in the VDCP are entitled to their contributions plus any earnings that have accrued.

   - The policies and procedures employed by the management of the Retirement System funds are subject to review by the Office of the Comptroller and external professional financial auditors.

     - Most recently, KPMG performed the external audit of the Retirement System pension trust funds. In KPMG's opinion, the reports of the Retirement System are prepared in accordance with generally accepted accounting principles.[6]
     - As noted by the Auditor, all legally required reserves are maintained by the Retirement System and were fully funded as of March 31, 2016.[7]

   - The VDCP is managed by TIAA CREF under a contract from the State of New York.[8]

2. **The asset allocations of the Retirement System pension funds are appropriate and provide for growth opportunities with reasonable risk. The asset mix in the VDCP is the result of the choices of employee participants.**

   - The allocation of invested assets of the Retirement System is shown in **Exhibit XV-2**. The investment mix by class is appropriate. It provides for growth opportunities with reasonable risk.

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[6] DR 277 Attachments 1 & 2

[7] DR 277 Attachment 2 p. 19

[8] https://www.tiaa.org/public/ms/nyvdc/employee.html

Exhibit XV-2
Allocation of Invested Assets of the Retirement System
(Millions of Dollars)

Investment Class	2016 Amount	Percent
Domestic Equity	$61,544	34.5%
International Equity	29,211	16.4%
Private Equity	13,961	7.8%
Total Equity	**104,717**	**58.6%**
Global Fixed income	44,661	25.0%
Real Estate	12,640	7.1%
Mortgage loans	796	0.4%
Total Real Estate	**13,436**	**7.5%**
Other	15,826	8.9%
Total Investments	**$178,640**	**100.0%**

Source: DR 277 Attachment 2 Retirement System Financial Reports.

- A primary determinant of the amount of risk is the percentage of funds invested in equity. The Retirement System has 58.6 percent of its funds invested in equity. This is similar to large utilities and manufacturers as shown in **Exhibit XV-3**.

Exhibit XV-3
Percentage of Equity in Selected Company Retirement Trusts

	Consolidated Edison	Exelon	Pacific Gas and Electric	Southern California Edison	PSE&G	General Electric
Equity	58%	56%	23%	48%	71%	57%

Source: Form 10-K of each listed company.

- The California Public Employees' Retirement System (CALPERS) is a state system for employees of a large state similar to New York. It has 60.8 percent of its assets invested in equity.[9]

3. **LIPA has no authority over fund manager selection of the Retirement System nor does it monitor the performance of fund managers. The Office of the Comptroller oversees all processes used by the Retirement System. The VDCP is administered by TIAA CREF Financial Services under an agreement with the State of New York and therefore LIPA has no authority over management or investment offerings.**

4. **Pension funds associated with LIPA employees are managed in the Retirement System in the same manner as funds for all other New York State, local or agency employees who are participants in the Retirement System. Funds in the VDCP are held in investments selected by the employee from the set offered by TIAA CREF.**

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[9] https://www.calpers.ca.gov/page/investments/asset-classes/asset-allocation-performance

- As explained in the Retirement System Governmental Accounting Standards Board Report, funds associated with LIPA employees are determined as an allocation of the entire, undivided retirement assets.[10]

5. **OPEB funds are invested conservatively, as is appropriate with the pay-as-you-go strategy employed by LIPA.**

- The funding of the Authority's net OPEB obligation is at the discretion of management and the Authority's Board. The net OPEB obligation is paid on a pay-as-you-go basis. However, during 2015, the Authority's Board authorized the creation of an OPEB Account to pre-fund future OPEB obligations of both Authority and PSEG LI employees (as discussed above). As of December 31, 2016 and 2015, the Authority deposited $1.8 million and $1.2 million, respectively, into this account to meet the OPEB obligations of Authority employees.[11]

- The Authority accounts for its OPEB obligations, in accordance with GASB Statement No. 45, *Accounting and Financial Reporting for Post-Employment Benefits Other Than Pensions*.[12] Actuarial valuations involve estimates of the value of reported amounts and assumptions about the probability of events in the future.[13]

- OPEB funds are not held in a trust.[14][15]

- Assets set aside for OPEB liabilities are invested as shown in **Exhibit XV-4.**

Exhibit XV-4
Statement of OPEB Assets at Market Value
(Thousands of Dollars)

Investment	2016 Amount	Percent
Vanguard Equities	$ 1,380.3	26.5%
Vanguard International Equities	613.5	11.8%
Total Equity	**1,993.8**	**38.3%**
Vanguard Fixed Income	613.5	11.8%
Vanguard Inflation Protected	460.1	8.8%
Total Fixed Income	**1,073.6**	**20.6%**
Chase Commercial MMDA	2,139.7	41.1%
Total	**$ 5,207.1**	**100.0%**

Source: DR 274 Attachment 1

- As shown in **Exhibit XV-4**, the relative amount of equity is 38.3 percent which is less than the Retirement System's 58.6 percent and the amount of cash or near cash held

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[10] DR 277 Attachment 1

[11] LIPA Audited Financial Statement thru December 31, 2016, Note 14

[12] For 2017 LIPA adopted GASB No. 75

[13] LIPA Audited Financial Statement thru December 31, 2016, Note 14

[14] DR 274 Attachment 1 p. 5

[15] For 2017 LIPA established a Sec. 115 Trust for the OPEB facilities for its own employees.

in Chase Commercial is relatively high at 41.1 percent. Both of these values reflect the short term nature of these funds related to LIPA's pay-as-you-go method of funding OPEB benefits.

6. **LIPA has not used fund managers for its OPEB funds. Funds are invested in public, professionally managed investments.**

7. **The OPEB funds controlled by LIPA are for the sole benefit of LIPA current and former employees.**

PSEG LI

8. **The SERVCO Thrift & Pension Investment Committee manages funds for PSEG LI employees in a different manner than funds for other PSEG employees are managed. Because the amount of funds in the trust for PSEG LI employees is much smaller than the amount for other PSEG employees, the funds are not actively managed, but are invested in passive funds.**

    - Because the fund for PSEG LI employees is separate from the majority of employees of PSEG and its subsidiaries, it has a much smaller value. As a result, the funds for PSEG LI are invested in public funds with passive management by the Trust Committee while the funds in the larger trust are actively managed. As shown in **Exhibit XV-5**, the amount of the PSEG LI trust was $134.2 million as of December 31, 2016.[16] The total funds in the PSEG pension trust as of the same date was $5,599.0 million.[17]

Exhibit XV-5
Allocation of Invested Pension Assets
(Millions of Dollars)

Investment Category	SERVCO		PSEG	
	2016 Amount	Percent	2016 Amount	Percent
Domestic Equity	$72.0	53.7%	$3,952	70.5%
International Equity	$23.7	17.7%		0.0%
Total Equity	**$95.7**	**71.4%**		**70.5%**
Fixed Income	$38.1	28.4%	$1,647	29.4%
Cash	$0.4	0.3%	$107.0	1.7%
Total	**$134.2**	**100.0%**	**$5,599.0**	100.0%

Source: DR 266 Attachment 7 and PSEG 10K for 2016. Note 12 to PSEG 2016 Consolidated Financial Statements.

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[16] DR 266 Attachment 7

[17] PSEG 10k for 2016

- Brad Barazini, of the PSEG Thrift & Pension Investment Committee, believes that funds will need to reach around $1.0 billion in order to implement active management.[18]

- Except for the lack of active management of the funds, the SERVCO Investment Committee utilizes similar procedures to monitor its investments in the PSEG LI (SERVCO) trust as the PSEG Committee does for the other funds in its trust, including regular reports to PSEG LI and to LIPA and periodic analyses by actuarial professionals.

9. **The asset allocation employed by the PSEG Pension and Investment Committee for the SERVCO funds is very similar to that used for the PSEG Trust.**

   - As shown in **Exhibit XV-5**, in the funds managed for SERVCO employees, equity is 71.4 percent of the total invested which is substantially the same as the 70.5% for PSEG.

   - PSEG has had actuarial studies performed that assess the risk associated with the proportion of equity in the SERVCO Pension Fund Trust.[19]

   - The Pension Trust Committee's target allocation for SERVCO trust is 70 percent.[20]

10. **Because the funds are passively invested, there are no fund managers to be selected or evaluated.**

11. **OPEB expenses for SERVCO employees are an obligation of LIPA during the term of the Amended and Restated Operating Service Agreement (A&R OSA) and upon termination of the agreement. It is LIPA's policy to fund an OPEB reserve account to provide payment for future OPEB expenses when they become due.**

    - The OPEB reserved funds are not a trust and are not managed as such. In the event revenues are not sufficient to pay reasonable and necessary Operating Expenses in any year, the Chief Executive Officer (CEO) or Chief Financial Officer (CFO) of LIPA may use the Reserve funds to pay operating expenses subject to approval of the Finance Committee of the Board.[21]

    - The current system for accumulating and managing OPEB funds does not involve fund managers or specific investment strategies.

D. RECOMMENDATIONS

None.

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[18] IR 73

[19] Notes to PSEG Consolidated Financial Statements for 2016.

[20] DR 266 Attachment 7

[21] DR 274 Attachment 2

APPENDIX
CUSTOMER BENEFIT ANALYSIS

INTRODUCTION

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) and PSEG Long Island LLC (PSEG LI) pursuant to Matter No. 16-01248.[1] This Appendix of our report provides a summary of our Customer Benefit Analyses (CBAs) to be considered by LIPA and PSEG LI in the development of their respective recommendation implementation plans.

Scope, Objectives and Audit Timetable

The audit was performed in accordance with the LIPA Reform Act (LRA) through its revision of the Public Service Law (PSL) §3-b(3)(d) and the Public Authority Law (PAL) §1020-f(bb). PSL §3-b(3)(d) affords the Department the discretion to have such audit conducted by an independent auditor chosen by and under terms negotiated by the Department, through a contract entered into between the independent auditor, LIPA, and the Department. The process used by the Department to select the independent auditor is similar to the process it currently uses pursuant to PSL §66(19), as applied to audits of investor-owned utilities. The LRA 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.

As indicated in the DPS Request for Proposal, NorthStar's audit proposal and the Final Approved Work Plan, the audit scope was comprehensive, focusing on LIPA's operations and management as performed by PSEG LI, 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,[2] the audit addressed:

- The Service Provider's construction and capital program planning in relation to the needs of its customers for reliable service;
- The overall efficiency of the Authority's and its Service Provider's operations;
- The manner in which the Authority is meeting its debt service obligations;
- The Authority's Fuel and Purchased Power Cost Adjustment clause and recovery of costs associated with such clause;
- The Authority's and its Service Provider's annual budgeting procedures and process;
- The application, if any, of the performance metrics designated in the A&R OSA and the accuracy of the data relied upon with respect to such application;
- The Authority's compliance with debt covenants;
- Corporate Governance; and
- The implementation of the recommendations from the Department's Comprehensive Management and Operations Audit of LIPA in Matter No. 12-00314.

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

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

The scope of work addressed 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
- 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. We examined operating conditions as they existed, with significant focus on how LIPA provides oversight of PSEG LI. The audit identified and addressed gaps and recommended improvement opportunities that will benefit LIPA's ratepayers as the management relationship with PSEG LI continues.

Customer Benefit Analysis

NorthStar's approach to developing the customer benefit analyses (CBAs) provides an overall context regarding the estimated financial consequences of implementing NorthStar's audit recommendations. Recommendations for improvements and/or change are economically justified and accompanied by supporting information, especially those involving significant implementation costs and/or savings.

For some recommendations, there is a direct correlation between the recommendation and the cost savings, for example improved productivity or a reduction in activity times. For others, specific costs or savings may be difficult to quantify. For those recommendations where the expected costs or benefits are difficult to quantify (e.g., adding or revising a policy) we provide qualitative measures and expected benefits. In other areas, the costs of implementation may be *de minimus* and not warrant a detailed cost analysis.

CBA Approach

NorthStar's CBA approach provides the structure to ensure recommendations are fully defined, realistic, can be implemented and are understood by LIPA and PSEG LI. In developing the CBAs, NorthStar worked with LIPA/PSEG LI in the development of the costs and savings projections. NorthStar used existing utility cost data and models where available, industry data, market data, NorthStar's expertise, and LIPA/PSEG LI input to assess how its recommendations will improve the utility operations and determine the associated costs and benefits.

Our analyses included estimated implementation durations (months or years) and quantified dollar benefit and cost streams, as appropriate, using the following model:

- For a recommendation that is expected to have quantifiable net dollar benefits, we defined known cost components and quantified as many as feasible. We also defined all benefit components and quantified as many as feasible.
- For a recommendation that does not have quantifiable benefits, but nevertheless is desirable (e.g., improved performance or good management practices), we defined cost components and quantified as many as feasible. We also defined all benefit components.
- At a minimum, we defined as many benefit and cost components as feasible so that if/when LIPA's and PSEG LI's implementation plans become available, those components can be more readily quantified.
- We also provide a methodology/format for LIPA/PSEG LI to capture the costs and benefits of implementing a specific recommendation.

We provide a five year schedule of estimated implementation costs and savings. In providing supporting information for recommendations, NorthStar included preliminary estimates of the following:

- Operating costs incurred before implementation of the recommendation.
- Operating costs to be incurred after implementation of the recommendation (one-time and recurring costs).
- Time frame for implementing the recommendation.
- Costs of implementing the recommendation and any annual O&M costs.
- Savings after consideration of implementation and O&M costs.
- Risks associated with not implementing the recommendation.

CBA Format

NorthStar provided a guideline to consolidate the recommendations and provide the cost-benefit analysis and estimated implementation timelines to be used by LIPA/PSEG LI in the development of a detailed implementation plan. A preliminary structure is provided below, but can be modified to meet the needs of the DPS Staff.

CBA Structure

Recommendation(s)	**Number(s)**	**Recommendation Text**
	May include multiple recommendations if part of one process	
Priority:		
Background:	Discussion of the findings to be addressed by the recommendation. To include discussion of the as-is state.	
Improvements:	Discussion of the improvements that will be realized from implementation – to-be state.	
Risks:	Discussion of the potential risks if they recommendation is not implemented.	

<table>
<tr><td>Expected Implement. Timeline:</td><td></td></tr>
<tr><td>Expected Improvement Timeline:</td><td></td></tr>
<tr><td>Cost Analysis:</td><td>Estimate of the operations and capital costs associated with implementation of the recommendations. Capital and O&M costs will be broken out, as will one-time and recurring costs. Costs will be specific to the department/ function and sourced/supported.
Potential costs include:
<table>
<tr><td>Labor</td><td>Department/function specific based on company specifics</td></tr>
<tr><td>Outside services</td><td>Training and development, consultant fees, outside contractors</td></tr>
<tr><td>Materials</td><td>Materials and equipment</td></tr>
<tr><td>Systems</td><td></td></tr>
<tr><td>Capital Costs</td><td></td></tr>
<tr><td>Other Costs</td><td></td></tr>
</table></td></tr>
<tr><td>Benefit Analysis:</td><td>Consider and define the following benefit components. Benefits such as improved productivity, reduced staffing, reduced expenses or capital requirements will be quantified.

Increased productivity
Improved reliability
Reduced expenses
Reduced capital requirements
Reduced full time equivalents (FTEs) – internal labor or contractors
Improved practices and processes
Improved schedule adherence
Improved work quality
Optimized organization
</td></tr>
<tr><td>Other Costs and Benefits:</td><td>Listing of those costs and benefits which may not be readily quantified such as improved practices and processes, improved schedule adherence, improved work quality, and optimized organizational structures</td></tr>
<tr><td>Five Year Payback Analysis:</td><td>One table each for capital and O&M costs</td></tr>
</table>

	Y1	**Y2**	**Y3**	**Y4**	**Y5**
One-time costs	$				
Increased annual costs	$	$	$	$	$
Cumulative costs	$	$	$	$	$
Annual savings		$	$	$	$
Cumulative savings		$	$	$	$
Net savings	$	$	$	$	$

CBAs

CBAs for each recommendation are provided on the pages that follow.

Recommendation II-1 LIPA Background and Prior Audit

Chapter(s)	**Rec. #**	**Recommendation(s) Text**
II	**1**	**LIPA and PSEG LI should work with the DPS to determine which of the outstanding recommendations from the 2013 Management and Operations Audit are still relevant and should be implemented.**
Priority:		Medium
Background:		Some of the 2013 audit recommendations are still no longer applicable to improving operations to LIPA as a result of the LIPA Reform Act and A&R OSA.
Improvements:		LIPA will only focus on relevant recommendations from the prior audit.
Risks:		None.
Expected Implementation Timeline:		Immediately following 2017 Management Audit report issuance.
Expected Improvement Timeline:		NA

Cost Analysis:

Nominal costs to determine current relevance of previous audit recommendations

Benefit Analysis:

Focus LIPA and PSEG LI resources on relevant recommendations.

Payback Analysis:

Not applicable.

Recommendation II-2 LIPA Background and Prior Audit

Chapter(s)	Rec. #	Recommendation(s) Text
II	2	**LIPA and PSEG LI should develop an implementation plan for all audit recommendations (new recommendations and outstanding recommendations that LIPA, PSEG LI and DPS determine remain relevant) within 90 days of the Final Audit Report acceptance and submit the implementation plan to the LIPA Board of Trustees and the DPS. The Report could take the form required of the IOUs..**
Priority:		Medium
Background:		LIPA and PSEG LI did not develop implementation plans for audit recommendations contained in the management audit completed in 2013 • While all of the audit recommendations were accepted by LIPA, the Board and PSEG LI, there was never a formal determination of responsibility, approach to implementation or timetable for implementation. • Reconstructing managerial responsibility for each recommendation as well as status of implementation proved to be a time consuming and difficult process. Management audit implementation plans are prepared by NY IOUs upon completion of management audits and regularly submitted to the DPS.
Improvements:		Adoption of an implementation program will minimize ambiguity over managerial responsibility and save significant resource time to monitor and track implementation progress. Unforeseen issues and challenges to implementation can more easily be brought to management's attention.
Risks:		If this recommendation is not adopted there will be missed opportunities for information and knowledge transfer, potentially higher labor costs to reconstruct activities retrospectively and missed opportunities for benefits.
Expected Implementation Timeline:		Within 90 days of acceptance of the Final Audit Report.
Expected Improvement Timeline:		Dependent on audit plan and individual recommendation implementation timetables.

Cost Analysis:

Nominal costs to develop an audit recommendation implementation plan.

Benefit Analysis:

Development of a plan is the first step to ensuring the audit recommendations will be implemented in a timely manner. Each recommendation has specific benefits as specified in the individual CBAs.

Payback Analysis:

Not applicable.

Recommendation II-3 LIPA Background and Prior Audit

Chapter(s)	Rec. #	Recommendation(s) Text
II	3	**LIPA Internal Audit should perform a comprehensive audit of the implementation status of all management audit recommendations annually until the next DPS audit is performed. The results of LIPA's audit should be submitted to LIPA executive management, the LIPA Board of Trustees, PSEG LI, and the DPS. Within each LIPA audit:** ▪ **An evaluation of progress performance should be included.** ▪ **A progress tracking document should show activities completed to date and those in process.** ▪ **Any revisions to completion targets should be highlighted for management review.**
Priority:		Medium
Background:		Internal Audit plans for 2014 to 2017 did not include reviews and status evaluations of the 2013 management audit recommendations and their implementation.
Improvements:		Unforeseen issues and challenges to implementation can more easily be brought to management's attention through an in Internal Audit review.
Risks:		Without a periodic comprehensive internal audit of recommendation implementation, it is possible that some recommendations will not be implemented on a timely basis.
Expected Implementation Timeline:		The first internal audit review of the implementation status of the 2017 management audit recommendations should be performed approximately 6 months following issuance of 2017 Management And Operations Audit report, and include a review of the status of the audit recommendation implementation plan development (see recommendation II-1).
Expected Improvement Timeline:		Dependent on audit plan and individual recommendation implementation timetables.

Cost Analysis:

Nominal costs to perform semi-annual audits of the 2017 Management and Operations Audit recommendations..

Benefit Analysis:

There are no direct cost benefits associated with the audit of recommendation implementation. Each recommendation has specific benefits as specified in the individual CBAs.

Payback Analysis:

Not applicable.

Recommendation III-1 Executive Management and Governance

Chapter(s)	Rec. #	Recommendation(s) Text
III	1	**LIPA Financial Oversight should formally document the results of its PSEG LI oversight activities and assessment process annually, with submission to LIPA/PSEG LI executive management as well as DPS.**
Priority:		Medium
Background:		LIPA Financial Oversight (FO) provides oversight of PSEG LI's utility operations by monitoring procedures and performance for budgeting, revenue forecasting and tracking, reporting of storm costs, meeting FEMA reimbursement guidelines, cost accounting allocations, affiliate charges, PSEG LI's rates, pricing and regulatory functions. FO also monitors PSEG LI's fiscal condition. ▪ FO monitors and reports on the financial operations of PSEG LI. PSEG LI is responsible for budget development, variance tracking and year-end projections specific to its operations. ▪ FO attends the Management Review Board (MRB) meetings to review performance data, and discuss operational and financial issues. ▪ FO also participates in monthly Scorecard meetings held jointly with PSEG LI. ▪ FO works with PSEG LI to gain an understanding of and monitor the use of affiliates in their operation of the LIPA owned system. Monitoring activities include a review of monthly charges as prepared by PSEG LI, and periodic review of PSEG LI due diligence with respect to such charges. In addition, FO will work with LIPA internal audit who has engaged outside experts to review and report on the accuracy and appropriateness of such charges. ▪ Determining the effectiveness and efficiency of using affiliates as opposed to alternatives such as outsourcing or staff additions. ▪ FO also reviews policies and procedures in many functional areas such as: - Release of materials from stores during a declared storm event. - Work with PSEG LI to develop capitalization criteria for materials consumed in declared storm events. - PSEG LI's Procedures for updating plant records and system maps. - PSEG LI's progress in its review of inside plant records. - Work with Legal and PSEG LI to undertake a review of the assessed valuations of certain sub stations and the related taxes being paid. - Establish Process for Closing Out FEMA Grants - Work with PSEG LI to monitor spending needs, forecasted needs of the service provider, anticipated recoveries, and rate adjustment mechanics in order to determine the need for a rate case in to be filed in February 2019.
Improvements:		Annual submission of LIPA Financial Oversight assessment reports to LIPA/PSEG LI executive management and the DPS will provide documentation for any significant PSEG LI budget variances and changes in PSEG LI financial practices, as well as LIPA's assessment of the changes. It will also ensure LIPA FO fulfills its oversight responsibilities.

Risks:	
Expected Implementation Timeline:	LIPA FO should start to maintain formal records of its activities immediately.
Expected Improvement Timeline:	Immediate and ongoing.

Cost Analysis:

Minimal costs, if any.

Benefit Analysis:

Improved transparency.

Payback Analysis:

Not quantifiable.

Recommendation III-2 Executive Management and Governance

Chapter(s)	Rec. #	Recommendation(s) Text
III	2	**LIPA should seek formal confirmation of extensions to Board member term periods at least six months prior to term expirations.**
Priority:		High
Background:		In accordance with the LRA, trustees serve staggered terms. Initial trustees were to begin service on January 1, 2014. At the time of this audit, three of the Trustees were continuing to serve although their terms had expired, and three more had terms that expired at the end of 2017. Only two Board member's terms extended beyond December 31, 2017.[1] In accordance with the Public Officer's Law: § 5. Holding over after expiration of term. Every officer except a judicial officer, a notary public, a commissioner of deeds and an officer whose term is fixed by the constitution, having duly entered on the duties of his office, shall, unless the office shall terminate or be abolished, hold over and continue to discharge the duties of his office, after the expiration of the term for which he shall have been chosen, until his successor shall be chosen and qualified; but after the expiration of such term, the office shall be deemed vacant for the purpose of choosing his successor. An officer so holding over for one or more entire terms, shall, for the purpose of choosing his successor, be regarded as having been newly chosen for such terms. An appointment for a term shortened by reason of a predecessor holding over, shall be for the residue of the term only. Trustee interviews indicated that there was uncertainty over whether their own terms of service on the Board would be extended as well as the terms of other Board members.
Improvements:		Uncertainty of Trustee terms is a governance weakness that can be remediated if LIPA takes a proactive approach.
Risks:		Uncertainty of Trustee terms
Expected Implementation Timeline:		Immediately.
Expected Improvement Timeline:		Immediately and ongoing.

Cost Analysis:

Minimal costs, if any.

Benefit Analysis:

Improved transparency.

Payback Analysis:

Not applicable.

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[1] DR 987

Recommendation IV-1 Enterprise Risk Management

Chapter(s)	Rec. #	Recommendation(s) Text
IV	1	**LIPA and PSEG LI should continue to develop an effective, comprehensive Enterprise Risk Management (ERM) process.**
Priority:		Medium
Background:		In 2017, LIPA began to develop an integrated LIPA/PSEG LI ERM process using a bottom-up approach and had workshops with LIPA departments to identify risks, key risk indicators, and mitigation plans. Towards the end of 2017, at the end of the audit, LIPA was staffing an internal ERM organization and working with PSEG LI to set up a joint steering committee and working group to execute the ERM process for PSEG LI/LIPA. In late 2017, PSEG LI planned to hire a full-time ERM resource, and expected the PSEG LI risk assessment workshop would start Q1 2018.
Improvements:		An enterprise-wide ERM will allow LIPA/PSEG LI to identify risks, quantify and prioritize risks, and proactively undertake activities to mitigate or manage those risks. The identification of financial and operational risks and monitoring of key risk indicators will improve LIPA/PSEG LI's risk culture and enable better corporate decision-making.
Risks:		Without an effective ERM process, risks may not be identified. With no responsibility for risk management and accountability for any risk events, LIPA and PSEG LI are vulnerable to risk events.
Expected Implementation Timeline:		The LIPA ERM staff estimated the completion of the initial round of risk assessments for the nine LIPA departments by May 2018. Once these are completed and reviewed with LIPA's Executive Risk Management Committee (ERMC) the LIPA ERM staff will create a high-level LIPA Risk Profile that will be reviewed with the ERMC at their May 2018 meeting. (DR 1008) The initial PSEG LI risk portfolio is projected to be completed by Q2 2019.
Expected Improvement Timeline:		Per LIPA, some benefits of a jointly developed/implemented LIPA and PSEG Long Island ERM Program have already been realized, including a structured framework for senior leadership involvement within both organizations, continuous ERM collaboration between groups to promote best practices, and increased risk awareness that is starting to permeate through all levels of the organization. Additional benefits will be realized through implementation of mitigation or action plans derived from the initial assessments to better manage or reduce risk, as necessary. Finally, monitoring and continuous feedback will lead to improved processes and procedures, identification of emerging risks, and continuous improvement. As the program matures, these benefits will continue to grow to include senior management's ability to gain greater insight and transparency into top risks and their drivers across the company and the determination if/when additional actions should be taken. Ultimately, senior leadership will be better positioned to guide strategic business decisions through risk-informed decision making. (DR 1008)

Cost Analysis:

As this is an on-going effort, there are no additional costs associated with implementing this recommendation. LIPA and PSEG LI ERM staff additions are included in the 2018 budget. The workshop process to develop departmental risk profiles takes time, but the manhours associated with this effort do not require additional departmental staffing. Moreover, going forward, risk management will be a routine part of each department's operations.

Benefit Analysis:

It is difficult to quantify the benefits of ERM. While many potential risks have a financial impact, and ERM may contribute to avoided costs by mitigating risks, these costs are not easily quantified. It is also possible that the existence of strong ERM program could contribute to favorable reviews from the LIPA's credit rating agencies.

Payback Analysis:

Not applicable.

Recommendation V-1 Budgeting and Financial Reporting

Chapter(s)	**Rec. #**	**Recommendation(s) Text**
V	**1**	**Continue to develop and implement the SOS capital program optimization model.** ▪ **Implement improvements identified by PSEG LI and LIPA Internal Audit, including:** - **Review and adjust the project description questions.** ▪ **Add a demographic category for "permitting required", which can act as a flag of sorts when running optimization scenarios.** ▪ **Flag projects that are necessary to remediate a violation or to prevent a violation.** - **Review the scoring criteria for each business area when setting up a new project in SOS.** - **Identify any biases toward certain types of projects.** - **Refine the Strategic Objectives and the Success Criteria. Consider including Success Criteria not used for the 2018 budget, such as NPV and the financial risk of deferral.** ▪ **Expand the use of SOS to other business areas, including IT and Customer Operations.** ▪ **Include a step in the SOS optimization process to calibrate value and risk scoring across business units that develop capital projects such as Network Strategy Planning group, Electric Operations, and Reliability Management. IDA should lead a process to review the scoring of projects with similar risk values to ensure the projects are scored on a comparable basis. Similarly, IDA should ensure the different organizations use comparable bases for value scoring the projects using the Strategic Objectives and the Success Criteria.**
Priority:		Medium
Background:		In late 2016/early 2017, PSEG LI began to change its project prioritization approach from a spreadsheet-based approach to the use of UMS Group's Spend Optimization Suite (SOS). The SOS tool scores projects in accordance with how they meet Strategic Objectives, and the Success Criteria that underlie each Strategic Objective. PSEG LI plans to use SOS to support its asset management decision processes; from identifying and prioritizing the risks and benefits, to analyzing investments and, ultimately, optimizing the portfolio of capital projects.
Improvements:		Implementation of SOS will improve PSEG LI's capital budgeting process. Using SOS will help PSEG LI to select the optimum bundle of projects that maximize strategic values for minimum cost. The strategic value contribution of each project is measured within the bundle. Improving the process will improve the quality of results.
Risks:		If PSEG LI does not continue with the implementation of SOS or another capital project prioritization/optimization process, it may not optimize the portfolio of projects included in the capital budget
Expected Implementation Timeline:		Begin immediately. While improvements may continue, PSEG LI should work toward key improvements completed in time for use in the 2019 budget preparation.
Expected Improvement Timeline:		Improvements should realized with preparation of the 2019 budget.

Cost Analysis:

There are no incremental costs as this is a planned activity already in process.

Benefit Analysis:

Improve quality of capital budgeting process and optimize the portfolio of projects iin the capital budget..

Payback Analysis:

NA

Recommendation V-2 Budgeting and Financial Reporting

Chapter(s)	Rec. #	Recommendation(s) Text
V	2	**Provide the LIPA-specific capital expenditure variance data to the BOT on a routine basis as part of the F&A package.**
Priority:		Medium.
Background:		LIPA's Finance department prepares a detailed monthly package which is presented to the Board's F&A committee. This report does not include an actual vs. budgeted comparison of LIPA-specific capital expenditures. LIPA capital variance is only reported to the Board annually as part of the budget package.
Improvements:		This will better inform the BOT about performance meeting capital budget goals.
Risks:		None.
Expected Implementation Timeline:		Immediate.
Expected Improvement Timeline:		Immediate

Cost Analysis:

Nominal.

Benefit Analysis:

BOT will be better informed. No monetary benefit is expected.

Payback Analysis:

Not applicable.

Recommendation V-3 Budgeting and Financial Reporting

Chapter(s)	Rec. #	Recommendation(s) Text
V	3	**Update the PSEG LI budget procedure to include the determination of incremental O&M expenses associated with new construction.**
Priority:		Medium.
Background:		PSEG LI forecasts depreciation expenses associated with new capital in its budget model. PSEG LI's budget procedure does not provide guidance regarding the determination of the amount of incremental O&M associated with new capital installations.
Improvements:		Identifying the O&M associated with planned projects will assure that new requirements will be included in the budget.
Risks:		None.
Expected Implementation Timeline:		Include in the budget for 2019.
Expected Improvement Timeline:		Effective January 2019 and forward.

Cost Analysis:

Nominal incremental costs. Determining projected O&M costs associated with capital project and including them in the O&M budget has a minimal impact on project estimating process and the compilation of O&M budget data.

Benefit Analysis:

Reductions in costs are not expected. However, the inclusion of the incremental O&M costs of new capital budgets will improved the accuracy of the O&M budget projects and reduce the risk that needed O&M might have to be foregone.

Payback Analysis:

NA

Recommendation V-4 Budgeting and Financial Reporting

Chapter(s)	Rec. #	Recommendation(s) Text
V	4	**Complete the process of upgrading LIPA's financial system.**
Priority:		Medium.
Background:		LIPA's current financial system, Epicor, has little customization and most accounting activity is manually posted to the Epicor general ledger. LIPA inputs monthly PSEG LI financial information in Epicor for consolidated LIPA/PSEG LI reporting. This information is consolidated at a summary level without visibility into the detailed transactions. LIPA attempted to automate the upload of the PSEGLI monthly financial statements template to EPICOR, LIPA's ERP system. Ultimately, the upload interface capability of EPICOR proved very problematic was deemed not feasible.[1] LIPA has many systems in place to ensure its financial statements and all compliance reporting requirements are accurate. However, many of these systems require manual intervention to maintain and these systems are not integrated with each other. LIPA's reporting software, Microsoft FRx, is used for financial reporting and analysis. Beginning 2011, Microsoft's mainstream support for FRx ended.[2] As of November 2017, LIPA was continuing its effort to replace its financial system, and plans to intensify this effort when it hires a new Chief Information Officer
Improvements:		The current approach for monthly closings and compliance reporting has been cumbersome, time consuming and is subject to human error and potential omissions. Many controls have been put in place to ensure errors don't occur, but once again this adds more time and manual control applications. Implementing a financial system that is integrated with information feeds from PSEG LI/SAP will reduce the manual effort required now to input data to the LIPA system. Reducing manual processes will also decrease the possibility of errors. A new financial system will also eliminate or reduce LIPA's need to use Excel spreadsheets to produce basic reports and analyses.
Risks:		Implementation of any new computer system has risks associated with it. However, LIPA can look at the experience of other companies to plan an effective implementation and select an appropriate system. Effective risks should be minimal.
Expected Implementation Timeline:		LIPA has decided not to proceed until a new CIO is on board. While this is a prudent strategy, it means that in all likelihood a new system cannot be selected until late 2018 or early 2019. It is always problematic to implement a new financial system mid-year so the likely implementation date is January 1, 2020.
Expected Improvement Timeline:		Benefits will begin at the January 1, 2020 implementation date and continue thereafter.

Cost Analysis:

LIPA has included approximately $5 million for a new ERP system in its 2018 capital budget[3]

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[1] DR 1009
[2] DR 1009
[3] DR 1009

Benefit Analysis:

The benefits from this system will be largely in increased capability and more assured data accuracy. A new financial system will also reduce the manhours required for data input and analyses as the use of manual spreadsheets will be replaced by more automated processes.

Payback Analysis:

LIPA states that new ERP system is being reviewed to lower the Authority's exposure to risk of error rather than for economic purposes.[4]

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[4] DR 1009

Recommendation V-5 Budgeting and Financial Reporting

Chapter(s)	Rec. #	Recommendation(s) Text
V	5	**Determine the feasibility and cost of establishing interfaces between PSEG LI's MicroStrategy, PCM, and SAP systems to eliminate the need for manual data transfer processes. If cost effective, implement processes to allow electronic data transfer between the systems.**
Priority:		Medium
Background:		The PSEG LI Planning and Budgeting (P&B) team uses the Profitability and Cost Management (PCM) System as its data warehouse and reporting system for the development of the operating and capital budgets. For the operating budgets, the P&B analysts complete Excel templates to load budget data such as headcount, labor allocation, and non-labor expenses by cost center. For the capital budgets, Business Work Planners provide capital information to the P&B Budget Analysts, who then upload the data into PCM. Once the budget is complete in the PCM system, the data is downloaded and formatted on an Excel file which is uploaded to PSEG LI's SAP business management software system.
Improvements:		Eliminating manual data transfer between systems will reduce the possibility of errors and improve the efficiency of PSEG LI's budget preparation process.
Risks:		None
Expected Implementation Timeline:		In 2019.
Expected Improvement Timeline:		Improvements will occurred electronic interfaces are established.

Cost Analysis:

None.

Benefit Analysis:

While there are expected efficiency improvements, it is unlikely they will have a significatnt cost impact.

Payback Analysis:

Recommendation VI-1 Debt Management

Chapter(s)	**Rec. #**	**Recommendation(s) Text**
VI	**1**	**LIPA should build on its success “homogenizing” groups of debt covenants to increase consistency among other debt instruments.**
Priority:		Low
Background:		LIPA has taken steps to “homogenize” its debt covenants. Most recently, in 2017, when establishing lines of credit with four banks in, LIPA succeeded in “homogenizing” the covenants and in allowing proactive reporting on its website rather than individual paper reports thus streamlining the process for both LIPA and its banks.
Improvements:		Homogenizing debt covenants will reduce the cost of administering covenant compliance. The new covenants allow proactive reporting on its website rather than individual paper reports, thus streamlining the process for both LIPA and its banks.
Risks:		None.
Expected Implementation Timeline:		Begin immediately and continue as other debt revisions occur.
Expected Improvement Timeline:		Begin immediately and continue as other debt revisions occur.

Cost Analysis:

Nominal costs

Benefit Analysis:

While the streamlined processes will improve efficiency, this does not result in substantial quantifiable cost benefits.

Payback Analysis:

Not applicable.

Recommendation VII-1 Load Forecasting, System Planning and DSP Development

Chapter(s)	Rec. #	Recommendation(s) Text
VII	1	**Develop evaluative criteria or other measures to assess the effectiveness of the planning process. Effectiveness should be measured based on specifics, for example:** • **Number and timeliness of system studies** • **Timeliness of development of PJDs** • **Quality of PJDs (e.g., do they contain all requisite information?)** • **Relative accuracy of conceptual level estimates.**
Priority:		Medium
Background:		PSEG LI has two system planning functions: transmission and distribution. Both groups are responsible for studying the system and recommending system solutions to support system thermal and load response. Currently, PSEG LI has no performance measures related to its planning process. Reliability indices such as SAIFI, CAIDI, and SAIDI are more representative of operation and maintenance activities (such as vegetation management) and not long term planning.
Improvements:		Provides an objective measure to validate that LIPA's system planning needs are met on annual basis and that planning needs are given the appropriate due diligence.
Risks:		There is no risk associated with this recommendation. Risks associated with not implementing this recommendation include foregone opportunities to improve the system planning process
Expected Implementation Timeline:		One year.
Expected Improvement Timeline:		One year.

Cost Analysis: The cost associated with this recommendation would be included in PSEG LI and LIPA's management of performance metrics and annual determination of metrics and their associated thresholds. While additional reporting maybe required, the fundamental activities to perform this recommendation exist.

PSEG LI prepares an annual 5 and 10 Year Transmission and Distribution Plan. The plan is based on numerous data gathering and study efforts. It is envisioned that the metric would quantify the activities that support development of the plan.

Benefit Analysis: The benefits associated with this metric are improvements in performance reporting providing LIPA a snapshot view into the timeliness and completeness of system planning activities.

Payback Analysis:

Not applicable

Recommendation VII-2 Load Forecasting, System Planning and DSP Development

Chapter(s)	Rec. #	Recommendation(s) Text
VII	2	**Perform detailed cost/benefit analyses consistent with Transmission Planning's analyses for projects related to thermal overload.**
Priority:		Medium
Background:		PSEG LI does not perform detailed cost/benefit analyses in the selection of system solutions; PSEG LI addresses risk in only two ways: feasibility and project scoring (risk). Utility infrastructure investments are driven largely by reliability requirements. Typically, the lowest cost option is selected. PSEG LI develops cost/benefit analysis for projects when a thermal overload occurs. For such projects, PSEG LI performs a three-part analysis: ▪ Present worth-analysis ▪ Benefit/Cost ratio ▪ First year rate impacts.
Improvements:		A cost-benefit analysis is used to evaluate the risks and rewards of projects under consideration. Cost-benefit analysis is useful as part of project prioritization or to justify project selection
Risks:		Without cost-benefit analyses, PSEG LI may not select the most cost effective projects to meet its needs.
Expected Implementation Timeline:		One year
Expected Improvement Timeline:		Upon implementation and on going

Cost Analysis:

There are no significant costs associated with implementing this recommendation.

Benefit Analysis:

Implementing this recommendation would result in better project alternatives analysis.

Payback Analysis:

Not applicable

CBA 20 – Recommendation VIII-1 Transmission and Distribution

Chapter(s)	Rec. #	Recommendation(s) Text
VIII	1	**Continue implementing the vegetation management program to meet annual targets. Complete the mainline hardening program.**
Priority:		High
Background:		PSEG LI's SAIFI has degraded from 0.71in 2013 to 1.11 in 2016. In 2014, PSEG LI transitioned to a four-year vegetation management cycle from a cycle of approximately six years. PSEG LI did not complete its trim cycles in 2014 and 2015, and was required to increase annual efforts to meet the four-year cycle in 2016 and 2017. The increased efforts resulted in increased vegetation management costs both on an annual and total cycle basis. PSEG LI has a FEMA-funded mainline hardening program. The purpose of this program is to strengthen LIPA's backbone distribution system by repairing damage from Superstorm Sandy, upgrade worn equipment and sectionalizing equipment to limit outages during storms. SAIFI on mainlines had degraded since 2013. PSEG LI's SAIFI improved in 2017 to 0.95 after completion of the vegetation management cycle and continued efforts in the mainline hardening program.
Improvements:		Improved SAIFI results.
Risks:		Declining SAIFI performance.
Expected Implementation Timeline:		Immediate
Expected Improvement Timeline:		1-2 years to return to target SAIFI performance.

Cost Analysis:

NorthStar does not anticipate any increased cost. Currently, both vegetation management and mainline hardening are funded programs.

PSEG LI has budgeted for these programs, as shown below:

	Vegetation Management	Mainline Hardening
2018	$42,700,000 [Note 1] 249 Transmission Miles 2,420 Distribution Miles Special Programs	$190,272,822
2019	$39,600,000 [Nte 2] 249 Transmission Miles 2,200 Distribution Miles Special Programs	$119,776,692
2014-2017 Annual Average	$32,636,131 250 Transmission Miles 2,470 Distribution Miles Special Programs	$69,000,000 (2014-2017) $120,000,000 (2016-2017) Program completion was schedule for 2018 but extended to 2019

Note 1: PSEG LI plans authorize an additional $5.7M for an additional 580 distribution miles, bringing the 2018 and 2019 mileage on tract with the four year program.
Note 2: Preliminary plans
Source: DRs 664, 1011 and NorthStar Report

Benefit Analysis:

There are quantitative and qualitative savings associated with meeting the vegetation trim cycle and completing the mainline hardening program including:

- Cost of unserved energy (sales and revenue not experienced during outages)
- Reduced storm restoration costs
- Reduced system “wear and tear”
- Improved reliability metrics

NorthStar does not have data avail ble to quantify these benefits.

Payback Analysis:

N/A

Recommendations VIII-2 and 3 Transmission and Distribution

Chapter(s)	Rec. #	Recommendation(s) Text
VIII	2	**Complete the Emergency Response Training for all employees as required.**
	3	**Improve Emergency Response Training description in the ERP to identify type of training and frequency by position.**
Priority:		High
Background:		PSEG LI issued a comprehensive emergency restoration plan (ERP) in December 2014 and has updated the plan annually. Per the ERP, all PSEG LI employees are assigned specific storm restoration assignments. The ERP recognizes that the normal functions of many employees are not part of daily system operations and that training is crucial to change the roles of these employees. According to PSEG LI, the responsibilities of approximately 1,200 employees do not change during a storm response. These employees do not require separate emergency response training. There are 1,100 employees whose emergency response roles are significantly different from their normal job responsibilities and who require supplemental training. Approximately 250-300 of these employees work in their general functional areas and receive instruction before an event. 800-850 employees required emergency response training, but only 519 employees have completed the requisite training. PSEG LI has developed an extensive list of classes and other training tools for its workforce. The ERP does not provide adequate detail of the training program and should include: • Job classifications that have traditional roles during an emergency response and do not require additional training • Job classifications that have non-traditional roles during an emergency response whose responsibilities do not change during an emergency response and do not require additional training • Job classifications requiring additional training including required training and frequency.
Improvements:		Correctly documented ERP and fully trained staff.
Risks:		None
Expected Implementation Timeline:		One year
Expected Improvement Timeline:		On going

Cost Analysis:

Implementation of these recommendations will have a nominal cost impact.

PSEG LI requires ERP training and it is included in the O&M budget.

PSEG LI updates the ERP annually. Enhancing the description of Emergency Response Training requirements will require additional documents and formatting. The information should be readily available as it is crucial to implementing the training program. NorthStar anticipates a one week work effort to make the necessary modifications and estimates incremental cost at $4,000 (40 hours x $100 hourly rate).

Benefit Analysis: The benefits from this recommendation are not quantifiable but are qualitative. They include:

- Properly documented ERP
- Trained staff
- Successful emergency response

Payback Analysis:

N/A

Recommendation VIII-4 Transmission and Distribution

Chapter(s)	**Rec. #**	**Recommendation(s) Text**
VIII	**4**	**Complete development of the Computerized Maintenance Management System (CMMS).**
Priority:		Medium
Background:		PSEG LI launched the CMMS in 2016 to provide real time asset health data to determine whether assets require enhanced maintenance and diagnostics and to assist in replacement decisions. CMMS is currently operating and will be fully implemented in 2020. CMMS is modeled after PSE&G's system. PSEG LI's CMMS project has the following scope of work:[1] • Purchase and install dedicated database servers for CMMS application. • Create a CMMS database (SQL based) and user friendly SharePoint front end. • Develop dashboards for various asset classes to view performance. • Assessment of existing asset data sources for targeted asset classes. • Create a method to collect data from various existing sources. • Create an active data link between SAP asset registry and CMMS system. • Create a data link between other useful asset data sources and CMMS system. For example; PI manually logger, equipment inspection data, GIS, SCADA, etc. • Implement mobile data collection and directly link inspection data to CMMS. • Develop and deploy condition assessment data algorithms for each asset class to drive output reports. • Pursue development of data analytics platform to provide predictive model for repair versus replace decisions. The scope presently includes the following asset classes; station transformers, load tap changers, circuit breakers, underground transmission cables, overhead transmission facilities, system relay protection devices and distribution network devices. Data for station transformers and circuit breakers is entered into CMMS for data analytics processing, which is intended to provide visibility into leading indicators of potential failure. Asset Management is continuing to accumulate and input data to provide intelligence within CMMS.[2] The need for trend analyses is identified but only a work in progress. SAP will continue to be used for inspection schedules as well as capturing the costs associated with the programs.
Improvements:		The improvements expected as a result of CMMS implementation include: [3] • Reduced expenditures on corrective maintenance and unplanned outages – a reduction in labor and materials costs • Proactive replacement of equipment prior to failure – a reduction in capital equipment cost • Lower costs and avoided interruptions – an improvement in reliability • Improved failure rates for critical asset classes – improved reliability • Allocation of maintenance expenditures to higher risk assets – productivity improvements • Centralized database for assets and performance data will support more efficient decision making – labor, equipment and materials cost reductions

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[1] DR 123 and 1005

[2] DR 912

[3] DR 1005

Risks:	If PSEG LI does not complete all phases of CMMS implementation it will not realize all the benefits of the system.
Expected Implementation Timeline:	The CMMS implementation project will be completed in 2020 following implementation of all phases: • Condition Assessment: 2015 – 2016 • Equipment Groups Condition Assessment: 2016 – 2019 • Repair/Replace logic development: 2018 - 2020
Expected Improvement Timeline:	Beginning immediately and gradually increasing until complete implementation at which time benefits will become steady-state.

Cost Analysis:

In December 2014 the UEB approved $2.7 million in capital expense (including a 42 percent increase covering Risk & Contingency) and $470, 000 O&M expenses. These expenditures were projected from 2015 through 2017.[4] PSEG LI did not provide cumulative expenses incurred to date, but did provide updated and significantly increased cost estimates. NorthStar was unable to find a "Capital Project Change Request" authorization for increased cost estimates.[5]

In response to a NorthStar data request, PSEG LI provided the following cost estimates for the 2015 to 2020 period:

Capital
- Direct system and licensing costs are estimated at $1.3 million
- Estimated labor costs for internal and external resources
  - External IT contractor & consultants costs: $3.4 million. PSEG LI will need supporting documents such as CPR form, RFPs, proposals, etc.
  - Internal labor costs: Over the duration of this project PSEG LI estimates that implementation will require (11 FTEs x $160,000) = $1,760,000 PSEG LI will need develop a rationale for what internal labor/organizations are included in the estimate.
  - Current total capital cost: $5,160,000.

O&M
- Training costs are estimated to be approximately $500K – $1 million for all stakeholders involved with this application. Timeframe for direct costs are quantified from 2015 through 2020. PSEG LI will have to develop a justification for the cost of training including planned participants and schedule. The current estimates would translate into approximately 5,000-10,000 "training hours" to learn to use an asset management data base and to make repair/replace decisions.
- Ongoing annual operational and maintenance costs are seen in two categories, one for T&D support and one for IT support costs. PSEG LI will have to develop a detailed estimate with supporting information.
  - T&D support is estimated to be approximately $160,000 to $240,000 annually for ongoing support. The Utility Technology organization has system maintenance responsibility within T&D. This cost was calculated assuming the activities to maintain CMMS would represent 1-2 FTEs' annual time at a loaded FTE cost of $160,000.
  - IT support is estimated to be approximately $750,000 annually (data center, hardware, software maintenance and IT resources to run production). This cost is calculated using a total system implementation estimated cost of $7-8 million and applying 10 percent IT maintenance cost to the total. PSEG LI will have to justify the assumption that IT resources increase at 10 percent of the IT capital budget each year.

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[4] DR 558 Attachment 9 page 31 of 416 CONFIDENTIAL

[5] DR 558 CONFIDENTIAL

Summary:
PSEG LI presents CMMS cost estimates totaling $5,160,000 in capital and ongoing O&M expenses of $1 million for training and $1 million annually for support.[6]

Benefit Analysis:

PSEG LI project benefits for this implementation: [7]

- "One time" economic benefits: None
- Equipment life extensions: Through the use of the CMMS output condition-based maintenance activities will proactively head off potential in service failures for critical asset classes. PSEG LI anticipates that over time (years), life expectancies will be extended beyond presently observed spans.
- Anticipated work quality improvements: The leveraging of multiple inputs relating to asset health data as well as the linking of SAP work management cost data will improve decision making in terms of prescribing the right type of maintenance at the right time. Performing maintenance on the most critical equipment based on CMMS driven health trends and refining the required maintenance budgets will improve overall system performance. Improved repair, replace or maintain decisions are anticipated to result from this system implementation.
- Materials and/or labor: Material and labor costs for corrective maintenance are expected to trend downward as equipment performance improves from the efforts described above.
- Timetable envisioned to begin to receive the benefits: The timetable for any benefits drawn from the CMMS implementation will be seen as each phase is rolled out into production and will be realized year on year. PSEG LI has already begun to draw value from the transformer and load tap changer condition assessments within CMMS by prescribing condition based maintenance activities during the 2017 time frame.

PSEG LI has pursued CMMS since 2014 without quantified estimates of actual benefits. PSEG LI must develop an estimate of the benefits in terms of labor, capital equipment and materials expenditures.

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[6] DR 1005

[7] DR 1005

Recommendation VIII-5 Transmission and Distribution

Chapter(s)	**Rec. #**	**Recommendation(s) Text**
VIII	**5**	**Continue monitoring SAIFI both from a system and cause basis. Continue targeting and prioritizing programs that address reliability.**
Priority:		High
Background:		SAIFI has degraded from 0.71 in 2013 to 1.11 in 2016. The PSEG LI OMS reports outage in sufficient detail to identify location, equipment and cause. PSEG LI also has developed asset management and maintenance programs including: ▪ Mainline Hardening ▪ Residential Underground Cable Replacement ▪ Substation Breaker Replacement ▪ Pole Replacements ▪ Distribution Transformer Replacements ▪ Circuit Improvement Program ▪ Distribution Infra-red Inspections ▪ Cable Testing Program ▪ Vegetation Management ▪ Multiple Customer Outages One aspect of preventive maintenance is to correlate outage information to potential system weaknesses and needs and then to develop programs that enhance reliability.
Improvements:		Improved reliability
Risks:		Reduced SAIFI performance
Expected Implementation Timeline:		Ongoing
Expected Improvement Timeline:		Ongoing

Cost Analysis:

There are no increased costs associated with this recommendation. This recommendation supports PSEG LI in their continuing efforts in maintaining detailed analysis of outage information, identifying system problems, and implementing reliability programs.

Benefit Analysis:

The benefits associated with this recommendation are qualitative and not quantitative. Expected benefits include:

- Better understanding of system conditions
- Identification of system weaknesses
- Development of targeted programs that will improve reliability, enhance maintenance operations, and assist in maintaining asset condition.

Payback Analysis:

N/A

Recommendation IX-1 Program and Project Planning and Management

Chapter(s)	Rec. #	Recommendation(s) Text
IX	1	**Perform all policies, procedures and control functions that are currently and formally required.** ▪ **PSEG LI should conduct all audits as required in the A&R OSA.** ▪ **Adhere to formal document control policies and procedures.** ▪ **PSEG LI should follow the Project Management Playbook (PMP) and its procedures.**
Priority:		High
Background:		PSEG LI has improved the procedures related to program and project planning and management. The procedures developed to-date address many components of project delivery, but as yet are not fully implemented to support project management and control. Section 4.13 of the A&R OSA requires that, in each Contract Year, the Service Provider shall conduct an audit of the Capital Improvements made in the prior Contract Year.[1] The audit shall measure the accuracy of the plant records, maps and maintenance databases concerning capital assets. Also, from time to time, the Service Provider must conduct a physical inventory of all capital assets.[2] PSEG LI's Project Management Playbook (PMP) was developed to guide project managers and the project team through the activities required when developing a capital project. The PMP defines a formal project life-cycle for the delivery of capital projects. The project life-cycle has five phases, where completed deliverables and activities permit movement to the next phase. PSEG LI's PMP (Procedure TD-PM-001-0003) provides the fundamentals for capital project delivery. The PMP covers: ▪ High-level roles and responsibilities ▪ Project Phases (Project Initiation, Preliminary Engineering, Detailed Engineering, Construction, Completion). ▪ Major Activities associated with each project phase ▪ Project Manager's responsibilities in each phase ▪ Level of Estimates Under the A&R OSA, PSEG LI's requirements include a description of each capital project constituting capital improvements in sufficient detail to enable LIPA to make a fully informed analysis and assessment thereof including (i) the project location, (ii) the planned initiation date and expected duration, (iii) an estimate of the amount of the costs including the dollar amount per year if the project requires more than a year to complete, (iv) an explanation of the relationship to other planned or subsequently required capital improvements, (v) the anticipated useful life of each capital improvement and (vi) the economic and engineering justifications for such project.[3]
Improvements:		Adhering to program and project planning and management policies and procedures will result in reduced expenditures for capital project labor and materials. Annual audits of capital improvements will, among other things, ensure the accuracy of the plant records, maps and maintenance databases concerning capital assets.

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[1] DR 4 – A&R OSA Section 4.13 B

[2] DR 4

[3] DR 4 A&R OSA Section 4.13 A

Risks:	Not following the program and project planning and management policies and procedures as outlined in the PMP may result in poor project management and controls, leading to cost overruns and schedule delays.. Without periodic audits of the capital improvements, plant records, maps and maintenance databases may not contain accurate data.
Expected Implementation Timeline:	Immediately
Expected Improvement Timeline:	Immediately

Cost Analysis:

The cost analysis below was developed by NorthStar and should be updated by LIPA and PSEG LI as necessary

- PSEG LI Internal Audit resources: 400 hours annually: (0.25 FTE x $160,000) = $40,000

Benefit Analysis:

- Benefits are addressed in other project management-related CBAs (IX-3, and IX-4 – IX-7).

Recommendation IX-2 Program and Project Planning and Management

Chapter(s)	Rec. #	Recommendation(s) Text
IX	2	**The URB management processes and controls should be audited annually until the next DPS management audit, to confirm adherence to its charter and control policies and procedures.**
Priority:		Medium
Background:		PSEG LI manages the LIPA capital program through its Utility Review Board (URB). The URB is responsible for: ▪ Providing oversight to PSEG LI's capital budget for the business planning horizon. ▪ Reviewing PSEG LI's investment projects to ensure affordability, priority, and possible alternatives analysis. ▪ Reviewing project alternatives to ensure appropriateness of pursued project. ▪ Reviewing PSEG LI's capital spending estimates for the upcoming year and tracking actual spending against estimates. The URB Charter is explicit in its responsibilities related to budget. NorthStar found that it was not possible to determine whether PSEG LI adhered to its URB Charter that requires formal approval for project changes: ▪ The URB meeting books did not include consistent minutes tracking actions and considerations. ▪ Capital Project Change Request forms are submitted to the URB for additional funding or timing and archived. However, meeting minutes, records discussion and formal acceptance or rejection of individual change requests were not recorded. ▪ Capital Project Change Requests submitted to the URB for approval lack detail and specifics regarding estimated funding increases that are necessary to understand the need for additional funding.
Improvements:		Periodic audits of URB management processes and controls will help to ensure that URB actions and decisions are based on the review of appropriate project data and the proper consideration of all alternatives.
Risks:		Without periodic audits of URB management processes and controls is possible that the URB does not fully execute its charter responsibilities in a controlled manner.
Expected Implementation Timeline:		Immediately
Expected Improvement Timeline:		Immediately

Cost Analysis:

The cost analysis below was developed by NorthStar and should be updated by LIPA and PSEG LI as necessary. There are only nominal costs.

- PSEG LI Internal Audit resources: 40 hours annually: (0.025 FTE x $160,000) = $4,000

Benefit Analysis:

Not applicable.

Recommendation IX-3 Program and Project Planning and Management

Chapter(s)	Rec. #	Recommendation(s) Text
IX	3	**Develop and implement procedures related to quality assurance and quality controls.**
Priority:		Medium
Background:		PSEG LI does not have formal or specific QA/QC policies, procedures or standards applicable to capital programs and projects.
Improvements:		A formal capital program/project QA/QC program will help to ensure the proper execution of project and program design, engineering and construction, and will help PSEG LI t0 successfully initiate, implement, and complete assigned projects safely, on schedule, and within scope and budget.
Risks:		Without a formal capital program/project QA/QC program, LIPA may not properly execute all requisite procedures and processes and negatively impact project scope, schedule and budget.
Expected Implementation Timeline:		Within two years following the issuance of the 2017 Management Audit report.
Expected Improvement Timeline:		Capital program and project execution should improve following feedback from the QA/QC reviews

Cost Analysis:

The cost analysis below was developed by NorthStar and should be updated by LIPA and PSEG LI as necessary

- One-Time External Consultant costs: $500,000.
- One-Time PSEG LI costs: 2,400 hours: (1.5 FTE x $160,000) = $240,000
- On-going execution of QA/QC program (6 FTE X $160,000) = $960,000

Benefit Analysis:

There are numerous economic benefits associated with improved program and project delivery; however, it is not possible to determine a detailed projection from the bottom up. PSEG LI's 2017 T&D capital budget is $423 million. If the QA/QC program ultimately results in a just 0.5 percent reduction in costs, this represents an annual savings of $2.1 million.

Payback Analysis:

The analysis below was developed by NorthStar and should be updated by LIPA and PSEG LI as necessary.

Five Year Payback Analysis:	.				
Capital					
	Y1	**Y2**	**Y3**	**Y4**	**Y5**
One-time costs	$750,000				
Increased annual costs		$960,000	$960,000	$960,000	$960,000
Cumulative costs	$750,000	$1,710,000	$2,670,000	$3,630,000	$4,590,000
Annual savings		1,000,000	$2,100,000	$2,100,000	$2,100,000
Cumulative savings		$1,000,000	$3,100,000	$5,200,000	$7,300,000
Net savings	($750,000)	($710,000)	$430,000	$1,570,000	$2,710,000

Recommendations IX-4 – IX-7 Program and Project Planning and Management

Chapter(s)	Rec. #	Recommendation(s) Text
IX	4	**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.** ▪ **Assess the process used to develop and update estimates for completion.** ▪ **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.** ▪ **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.** ▪ **Continuously verify the accuracy of estimates versus the actual project cost.**
IX	5	**Utilize a WBS in the initial phases of the project justification and conceptual estimating, and continue their refinement as the project progresses.** ▪ **Develop well-defined work packages that can be used to track and measure project performance based on earned value.** ▪ **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 PSEG LI's accounting 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.**

		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.
IX	**6**	**Formalize and incorporate contingency management in capital project cost estimating and cost management. Formally report the expenditure of contingency funds separately from project estimates rather than inflated project budget amounts.** **It is critical that reliable 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.**
IX	**7**	**Define and report project management performance measures that focus on the effectiveness of cost estimation, earned value and schedule management. Project progress reports should be timely, and contain all information which is pertinent for their target audience. 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.** ▪ **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.** ▪ **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.** ▪ **Establish processes for systematic schedule preparation, review and analysis.** ▪ **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.** **▪ Highlight:** **- 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.**
Priority:	**High**
Background:	**The effectiveness of program and project management must include the integration of 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. 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, 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)** **▪ Publicly Available Specification (PAS) 55: 2008 Specification for the Optimized Management of Physical Assets Parts 1 and 2, British Standards Institution** **▪ Project Management Institute Government Extension to the PMBOK Guide, 3rd Edition** **▪ Standard for Program Management, 2nd Edition, Project Management Institute** **The Amended and Restated Operations Service Agreement (A&R OSA) dated December 31, 2013 assigns PSEG LI broad responsibilities in the capital improvement, operations, and maintenance of the transmission and distribution systems. Responsibilities include the development and preparation of:** **▪ Recommended capital plans and the monitoring of the approved annual capital budget.** **▪ Risk assessments and analyses in support of capital projects prioritization and planning.** **▪ Long and short range system plans, including integrated electric resource plans.** **▪ Proposed annual operating and maintenance work plan.** **▪ 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.** **- Project management services to ensure the technical performance and**

	reliability of the T&D system. - **Meeting 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.** ▪ **Capital improvements and repair or modification activities required due to Public Works Improvements.** **PSEG LI manages the LIPA capital program through its Utility Capital Review Board (URB). The URB is responsible for:** ▪ **Providing oversight to PSEG LI's capital budget for the business planning horizon.** ▪ **Reviewing PSEG LI's investment projects to ensure affordability, priority, and possible alternatives analysis.** ▪ **Reviewing project alternatives to ensure appropriateness of pursued project.** ▪ **Reviewing PSEG LI's capital spending estimates for the upcoming year and tracking actual spending against estimates.** **The URB is composed of seven members including the President of PSEG LI, his direct reports, and the Director of Finance. The URB approves funding for:** ▪ **All T&D capital improvement projects including facilities, blankets and specific projects. Blankets are a number of similar projects that are less than $250,000 in aggregate. Specific projects are greater than $250,000.** ▪ **All IT projects greater than $500,000.**[1] **The PSEG LI Transmission and Distribution Planning Coordinating Council (TDPCC) is responsible for providing updates on current and future projects. The Council is comprised of LIPA and PSEG LI Directors, Managers and Engineers.**[2] **The "recognized good practices" contained within the references noted above, when evaluated against current PSEG LI program and project management practices result in recommendations IX-4 through IX-7. These recommendations must be implemented and work in concert to assure the effectiveness of PSEG LI's program and project management.**
Improvements:	**Increased value for expenditures in labor, equipment and materials due to improved work practices and management decision-making.** **Improved monitoring and control of the capital project portfolio, and each operating organization's program portfolio.** **Improved collaboration, document management, project transparency, schedules and resource management.**
Risks:	**The lack of formal procedures and their implementation lead to poor project performance – expenditures over estimates and budget, poor quality, material waste, incorrect functionality and delayed commercial operational dates.** **It is important that program and project status information be documented and reported to stakeholders in an efficient format – that is validated by and integrated with related management reporting processes.** **If cost and schedule information is not based on reliable estimates, reported consistently and on a timely basis, PSEG LI cannot take the necessary corrective action to keep capital projects on track.**
Expected Implementation	**Three to five years for full implementation.**

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[1] DR 558

[2] DR 62

Timeline:	
Expected Improvement Timeline	**Three to five years for full implementation**

Cost Analysis:

- PSEG LI-estimated direct cost of the SAGE system licenses and related software is $177,000
- Estimating system:
  - Labor for IT and Line of Business resources: $212,000
  - Vendor labor: $156,000
  - Overhead and facilities related charges: $122,000
  - Training: $15,000
- Related Cloud, AWS maintenance, Eos, knowledge base, etc.: $48,000
- Business Services Resources - An additional 4 FTE's will be required for ongoing design, enforce and maintain project management standards across the enterprise, and support the delivery of the project scope identified:
  - 4 FTE's at $160K - $520,000.
- SOS Portfolio Management System – no additional resources anticipated. Approved funding for SOS was in CY2014.[3]
- Project Management System – For the Primavera P6 implementation across all organizational units, PSEG LI's "Prior Approved Full Funding" was $900,000 in CY2015 and CY2016.[4] O&M expenditures were $130,000 for the same time period – considered ongoing for enterprise-wide P6 implementation will include costs for software, hardware, integration, maintenance, etc..
- Finding for SAP integration with P6 to manage schedule and cost data for T&D projects received approved funding of $900,000.[5]

<u>Summary:</u>

Based on the LI cost estimates above, the total costs of this recommendation is as follows:

- Direct costs: $2,530,000
- Ongoing O&M costs: $650,000

Benefit Analysis:

Improved enterprise-wide project management systems and processes, and formal, controlled procedures will provide the following expected benefits:

- Ability to deliver higher portfolio value with the same capital spend, or the ability to deliver the same portfolio value with reduced capital spend.
- Projects and available resource capability aligned thereby improving resource utilization/labor cost.
- Projects scheduled and executed for the highest impact/lowest risk.
- Improved skills assignment.
- Improved estimating tools.
- Best-practice methodologies and lessons learned identified and implemented thereby improving performance.
- Standardized project management methods which shorten the learning curve for other organizational units.
- A better basis for skill set and resource transfers across organizations thereby reducing training, improving labor costs and overall capability.
- Better project management and oversight.
- Improved collaboration of team members.
- Better, more consistent document control.
- Project cost and schedule control.

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[3] DR 558 Attachment 9 page 77 of 416
[4] DR 558 Attachment 9 page 65 of 416
[5] DR 558 Attachment 9 page 75 of 416

- Risk management.
- Improved, standardized reporting capabilities for project team and utility management.
- Compliance with authorization requirements and procurement policies.

Improved project management and implementation of lessons learned may also result in the following benefits:

- Decreased project costs – reduction in materials and labor costs.
- Improved project schedules – more timely execution of important projects and commercialization.
- Improved workforce productivity – reduced labor costs.
- Improved budget monitoring – improved cost management and reduced waste.

Summary of estimated benefits:

- Benefits in terms of increased project work for the same funding levels, reduction in spending levels, or a combination of both would translate into 1 to 5 percent of the 2018 Approved Capital Budget ($423,212,000) or $4 to $20 million dollars annually.

Payback Analysis:

- PSEG LI should identify savings after development of the first implementation plan,.

Recommendations X–1 and X-2 Work Management and Outside Services

Chapter(s)	**Rec. #**	**Recommendation(s) Text**
X	**1**	**Develop integrated work management systems covering all PSEG LI operations, maintenance and construction resources that is based on engineered time standards and covers routine operations, repetitive maintenance activities, planned work, support requirements, and provides continuous feedback on workforce effectiveness.** **The system should be in an easy-to-use format expressed in man-hours, 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 workforce levels.** ▪ **Documentation of criteria for adding contractor capacity.** ▪ **Establish real time variance reporting for project costs.** ▪ **Additional decision-making information to work plans.**
X	**2**	**Fill gaps in the current management information reporting and organizational reporting relationships to support an integrated work management system.** ▪ **Develop formal reports on trends in work load levels, workforce productivity and utilization. The analysis of these trends identifies areas that are performing well, where improvements are needed, and is a foundation for the development of strategies to improve work force performance.** ▪ **Establish formal processes to use work management data for annual resource planning as part of the annual business planning activities of PSEG LI operations and maintenance.** ▪ **Develop formal work management practices for PSEG LI engineering and design functions. The work management systems should have appropriate system tools to support the various individual and distinct engineering functional processes. Elements that should be formalized include:** - **Scheduling** - **Prioritization and planning** - **Resource allocation and leveling** - **Performance measurement** - **Budget planning and control** - **Vendor tracking** - **Document/drawing control** - **Records management** - **Procurement management** - **Time reporting.**
Priority:		High
Background:		Work definition is the description, documentation and communication of all activities needed to accomplish objectives, including a standard or estimate of resource requirements in man-hours. Work definition involves the determination of the work performed and allocation into discrete, measurable units. PSEG LI T&D organizations do not have formal, standardized work management processes. While some organizations and functional areas have made improvements for planning, scheduling and reporting work, none have sufficient data and tools to support a continuous improvement effort. Work definitions that have been defined to date do not include man-hours required to perform the core work activities. Without quantification the fundamental processes of work management including scheduling, work order procedures, progress reporting against tasks, quality controls, or performance measurements such as productivity, utilization,

	lost/delay time and trend analyses cannot be supported. PSEG LI has begun to address work management but as yet does not use work management systems to effectively plan, monitor and control the work of major work force groups. PSEG LI's major construction and maintenance work groups include: - Engineering - T&D Overhead and Underground - Substation - Distribution Operations Currently, T&D construction, operation and maintenance workload quantification is based on institutional knowledge and historical relationships between budgets and resource levels. Discussion of the workload and any potential conflicts are continuously addressed and prioritized at the Planning, Resource and Engineering (PRE) management meetings.[1] From a system design perspective, the internal PRE engineering design managers meet and discuss the transmission and substation capital work load at the Engineering Work Plan meeting. PSEG LI maintenance work in T&D and Substation include some work definitions (e.g., test and repair instructions) and historic time durations, but they are used infrequently as reference material. PSEG LI uses historical trends and budget levels to establish staffing requirements for operational groups that perform preventive maintenance (T&D maintenance and construction, field service, warehouse, workshops, fleet management/maintenance).[2] To prepare its rate plan submission for 2016-2018, PSEG LI used historical maintenance activities/budgets as a baseline to determine the required preventive maintenance and associated budgets. PSEG LI increased preventive maintenance activities and its forecast annual preventive maintenance spend in the budget it presented for BOT approval.[3] On-going staffing requirements are managed by the managers within the operational groups. When additional staffing is required, the managers will make a request to their Directors and ultimately to the PSEG LI President & COO. An Excel file is used by the T&D Business Partner to track staffing.
Improvements:	The use of work management data for resource planning will increase effectiveness in determining work and man-hour requirements, including changes in preventive maintenance scope and frequency, and productivity. The analysis of trends identifies areas that are performing well, where improvements are needed, and serves as a foundation for the development of strategies to improve work force performance.
Risks:	Not performing routine trend analyses may result in sub-optimal decision-making and increased costs.
Expected Implementation Timeline:	To the extent possible, the implementation of routine trend reporting should be done in conjunction with any planned work management system improvements, such as those planned for PSEG LI T&D operations, maintenance and support functions. To start, each of the T&D organizations should perform a gap analysis of their respective work management systems and processes, covering the functional processes: ▪ Scheduling ▪ Prioritization and planning ▪ Resource allocation and leveling ▪ Performance measurement

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[1] DR 63

[2] DR 87

[3] DR 548

	▪ Budget planning and control ▪ Vendor tracking ▪ Document/drawing control ▪ Records management ▪ Procurement management ▪ Time reporting. The gap analysis will identify the need for work management system and process improvements in each organization and should be performed by end of year CY2018. Following the gap analysis, PSEG LI should determine what can be leveraged from current development efforts such as SAP and CMMS: ▪ Prepare a document which provides an overview of work management improvement program to share among other T&D operations, maintenance and support organizations. The overview should describe the purpose, methodology, and results of each initiative, including the impact on the work processes. ▪ Each organization should determine and quantify the potential to improve its operations, and to identify other opportunities to improve its work processes. Once all PSEG LI T&D organizations identify their work management needs, and assess the applicability of the existing initiatives, PSEG LI should determine the steps for development and implementation of an enterprise-wide program. This program should be fully defined during CY2019.
Expected Improvement Timeline:	Upon implementation and ongoing.

Cost Analysis:

A thorough gap analysis should be performed by an independent consulting firm with requisite expertise in work management and industrial engineering. NorthStar estimates that this could cost $500,000 to $1,000,000.

Developing engineered standards for PSEG LI operations, maintenance and support functions along with work management reporting should be performed by a combined PSEG LI and independent consulting firm.

PSEG labor estimate: $1,000,000

Contracted labor: $2,000,000

Benefit Analysis:

Benefits associated with engineering work management processes and systems include:

- Framework for prioritizing engineering workload
- Improved means of tracking funding commitments, and using this information in the budget control and performance measurement processes
- Improved means to capture, track, and schedule work backlog
- Consolidation of tools, and consistency in the methods, processes, and convention employed for all aspects of T&D manpower planning and scope management
- Improved time reporting, formatted correctly for work management, providing the appropriate link to schedule updates and the performance measurement, and the ability to communicate with PSEG LI accounting
- More flexible, comprehensive reporting and feedback mechanisms enabling a quicker and more effective response to management requests
- Improved historical data repository for all work categories to improve future planning and budget management
- Complete, integrated work plans which assist operations, maintenance and support personnel in managing their entire workload, and which are responsive to day-to-day work load dynamics
- Expanded scope of schedule and resource management representing all competition for all resources

- Improved work completion commitment planning
- Improved scope control due to the availability of information to accomplish work scope tradeoffs at all levels in the T&D organization
- Improved link between budgeting and workload requirements.

Savings include productivity improvements, and reduced costs through more-informed resource planning. Based on a 1 to 5 percent productivity improvement and CY2017 budget levels, this could represent $1 to $4.75 million annually.

(1% x $189,797,000[4]) x (half materials/half labor) = $1 million to $4.75 million

Payback Analysis:

Northstar cannot peform payback analysis without additional data, such as the annual labor cost of T&D resources.

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[4] DR 782

Recommendation X-3 Work Management

Chapter(s)	Rec. #	Recommendation(s) Text
X	3	**Develop overtime targets for PSEG LI operations and maintenance organizations based on economic analyses and verified industry norms.**

Priority: Medium

Background:

PSEG LI T&D organizations do not have targets for overtime charges and budgets show expected levels of overtime as operating norms.

Overtime rates are not considered in PSEG LI performance KPIs or performance metrics.

Overtime rates exceeding 15 percent of standard time are often considered to be economic indicators that staffing levels and work management processes need attention.

NorthStar requested procedures that PSEG LI uses to establish staffing requirements for LIPA operational groups such as T&D maintenance and construction, field service, warehouse, workshops, fleet management/maintenance, purchasing, dispatch, including example forms and reports.[1] PSEG LI responded that staffing was proposed and ultimately recommended in the 2015 Three Year Rate Plan. The on-going staffing requirements are managed by the managers within the operational groups. When additional staffing is required, for example, for hiring above the rate of attrition because of long lead training requirements for key roles, the managers will make a request to their Directors. If the Directors determine that the additional staffing is required, the Director will seek approval from the Vice-President of T&D Operations. Once approved by the Vice-President, the Vice-President reviews the staffing requirement with the President & COO. Upon Final Approval by the President & COO, the operational managers work with their Human Resources Business Partner to track the approval and follow the internal processes for hiring. An excel file is used by the T&D Business Partner to track staffing. In summary, regardless of best intentions PSEG LI staffing is subjective.

Significant levels of overtime warrant closer management attention to work force management systems and improvement programs. During 2014, PSEG LI operated on National Grid's SAP platform with National Grid contract services. As a result, 2014 overtime and straight time data is not readily available to PSEG LI and would require significant time, effort, and expense to obtain. Overtime levels for CY2015 and CY2016 are shown below.[2]

PSEG LI Overtime Charges for 2015 and 2016

Functional Area	Overtime Hours -2015	Straight Time Hours -2015	
NJ Asset Mgmt.	155	20,150	
Planning, Resources and Engineering	10,867	278,432	
T&D Services	21,628	187,908	
Overhead / Underground	200,010	613,046	
T&D Operations	129,260	349,934	
Projects and Construction	5,502	109,806	
Substation Protection	103,346	395,867	
Emergency Planning	324	21,043	
Total T&D	**471,092**	**1,976,187**	**23.8%**

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[1] DR 87

[2] DR 846

Functional Area	Overtime Hours -2016	Straight Time Hours -2016	
NJ Asset Mgmt.	300	20,879	
Planning, Resources and Engineering	15,066	253,520	
T&D Services	34,365	176,181	
Overhead / Underground	229,895	631,868	
T&D Operations	178,228	380,368	
Projects and Construction	12,098	121,007	
Substation Protection	142,715	414,944	
Emergency Planning	589	22,976	
Total T&D	**613,255**	**2,021,744**	**30.3%**

Source: DR 846

Overtime is a practical necessity for utility services. However, industrial guidelines suggest that economic alternatives to overtime levels that exceed 15 percent exist and should be considered by management.

Improvements:	Specific overtime targets for each T&D organization that are based on economic analyses and verified industry norms will encourage more effective resource management.
Risks:	None
Expected Implementation Timeline:	Two to three months to perform analyses to determine appropriate overtime targets for 2019. Analyses should be performed annually thereafter.
Expected Improvement Timeline:	2019 and ongoing

Cost Analysis:

The following assumptions are used to estimate the costs of developing specific overtime targets for PSEG LI operations using pertinent data, including economic factors and industry norms, future work plans, budget constraints, and resource capability.

Step 1) Determine industry overtime norms.

- Assume $250,000 to obtain overtime survey results every two years.

Step 2) Develop annual overtime targets.

- Assume no additional costs to develop annual overtime targets using economic factors and industry norms. PSEG LI currently develops overtime targets for each T&D organization.
- The labor cost to determine the overtime targets for T&D field organizations is determined as follows:
  - 100 hours – this includes time for development of targets and appropriate reviews
  - Average fully loaded rate $100/hour
  - Number of analyses – 16, for the organizations highlighted in the table above and reported by PSEG LI. More analyses may be performed to determine targets at a Division level.
  - Estimated cost : 16 analyses X 100 hours/analysis X $100/hour = $160,000 per year

Benefit Analysis:

Managing to appropriate overtime target should result in lower overtime rates, and lower costs.

NorthStar does not know what the revised target overtime rates will be. Quantification of costs and benefits will be dependent on benchmarking, targets set and applicable to organizational units on an individual basis.

Reduction of 2015/2016 overtime levels to 20 percent would translate into 40,533 hours per year or $3,040,012.

(81,067 hours ÷ 2) x ($100 per hour x overtime premium pay net standard pay 0.75) = $3,040,012

Recommendation X–4 Work Management and Outside Services

Chapter(s)	**Rec. #**	**Recommendation(s) Text**
X	**4**	**Add KPIs to position descriptions. Review the design of monitoring and controlling reports to improve their usefulness.**
Priority:		Medium
Background:		Current work management metrics cover only a portion of the relevant work activity and do not include measures of productivity, efficiency, effectiveness, and utilization. • Some management reports contain performance metrics but functional coverage is mixed. • Performance KPIs for PSEG LI Electric Operations management positions could not be provided.[1] • KPIs can be found in a variety of management reports but these are broad, functionally focused. NorthStar requested a summary of Electric Operations performance metrics.[2] PSEG LI provided a list of over 60 metrics – measurements purported to demonstrate effective achievement of business objectives. PSEG LI stated that a Key Performance Indicator is a measurable value that demonstrates how effectively a company is achieving key business objectives. Organizations use KPIs at multiple levels to evaluate their success at reaching targets. However, not all organizational functions are addressed by PSEG LI, metrics lacked definitions and their relationship to business objectives was not always apparent.
Improvements:		Objective and realistic targets improve performance. Increased communication within the workforce improves understanding of organization and business priorities. Meaningful KPIs align corporate objectives with employee development.
Risks:		None
Expected Implementation Timeline:		Ideally changes to performance targets and employee development KPIs should be included in the 2019 business planning and development process. Budget/KPI guidance will be provided in the 2017 budget / business planning guidelines mid 2018 for the CY2019 operational year.
Expected Improvement Timeline:		2019 and ongoing

Cost Analysis:

No incremental costs associated with the KPI development process currently exists. PSEG LI does not perform quantitative assessments of the cost of achieving performance improvements relative to the benefits (e.g., would the cost to increase reliability result in a significant improvement in customer satisfaction.)[3] Potentially nominal/minimal costs associated with increased employee communication of KPIs and performance and more prominent identification of KPI would result.

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[1] DR 847

[2] DR 847

[3] DR 558

Benefit Analysis:

Implementation of this recommendation should result in the following benefits:

- Improved performance
- Potential improvements in employee morale associated with increased communication

Payback Analysis:

To be performed by PSEG LI in the process of setting more aggressive performance targets.

Recommendation XI–1 Customer Operations

Chapter(s)	Rec. #	Recommendation(s) Text
XI	1	**At the time of the next bill redesign, revise bill formats to include missing information required by 16 NYCRR Parts 11 and 13 (e.g., definition of kW, late payment date line, and an explanation as to how the bill can be paid).**
Priority:		Low
Background:		Commercial customer bills do not include a definition of "kW." 16 NYCRR Part 13 requires an explanation of all abbreviations displayed on the bill. PSEG LI acknowledges the oversight and agrees to include a definition on the next revision to the bill format. Residential time-of-use bills do not include the late payment date line. 16 NYCRR Part 11 requires the display of the late payment date. PSEG LI acknowledges the oversight and agrees to include this information on the next revision to the bill format. Residential bills do not include the location of local payment offices or a listing of authorized offices or payment agencies. 16 NYCRR Part 11.16d requires that bills include "an explanation of how the bill may be paid, including one or more local distribution utility offices at which it may be paid, and a statement that bills may be paid at other authorized offices or payment agencies."
Improvements:		Including this information on customer bills is in compliance with HEFPA
Risks:		None.
Expected Implementation Timeline:		These revisions should be included as part of the next bill update.
Expected Improvement Timeline:		Immediately upon bill revision

Cost Analysis:

Nominal costs. This will be done as part of PSEG LI's next bill update.

Benefit Analysis:

There are no direct cost benefits. Including this information on customer bills is in compliance with HEFPA.

Payback Analysis:

NA

CBA – Recommendation XI–2 Customer Operations

Chapter(s)	Rec. #	Recommendation(s) Text
XI	2	**Issue denial of service letters as required by 16 NYCRR Parts 11 and 13. Offer payment arrangements as required by 16 NYCRR Part 11.**
Priority:		Low
Background:		PSEG LI's definition of "denial of service" may not be technically consistent with the requirements of HEFPA. PSEG LI does not consider it to be a "denial of service" if the applicant is told that he/she must go to the office and provide additional information, as the customer has not yet technically made an application. As a result, these customers are not sent the letters required by HEFPA Section 11.3(b)(2). Section 11.10 of HEFPA qualifies applicants for payment arrangements who have not broken a previous payment arrangement requires a written offer of a payment agreement when payment of outstanding charges is a requirement for acceptance of an application for service. In a review of Denial of Service letters, NorthStar found that in practice, payment plans are offered if the service was terminated in less than the previous 60 days, otherwise full balance is required.
Improvements:		Compliance with HEFPA.
Risks:		None.
Expected Implementation Timeline:		Within six months of the issuance of the final report.
Expected Improvement Timeline:		Immediate

Cost Analysis:

At a minimum, costs include printing and mailing, and may requires system modifications or manual workarounds. These costs should be determined by PSEG LI and included in the audit implementation plan.

Benefit Analysis:

There are no direct cost benefits. Implementation of this recommendation is required to comply with HEFPA.

Payback Analysis:

NA

Recommendation XI–3 Customer Operations

Chapter(s)	Rec. #	Recommendation(s) Text
XI	3	**Revise the processes used by PSEG LI to respond to complaints received by the DPS as follows:** ▪ **Create a case file checklist to include in case files to ensure documentation is complete.** ▪ **Develop an integrated program management approach to ensure customers are provided information on all programs available to them. One approach would be to create customer profile worksheet with cross reference to applicable programs and/or relevant protections.** ▪ **Eliminate practice of hand calculations and implement use of excel template calculators.** ▪ **Modify the "DPS Complaint Response Form" to include:** - **Time and date customer complaint was created** - **Applicable customer contact timeline (e.g. 2-hour, next day etc.)** - **Time and date customer was contacted** - **Any special protections or customer assistance programs the customer was referred to** - **Date form submitted to DPS.** ▪ **Implement a process to ensure PSEG LI includes copies of the DPS customer close out letters in the case files.**
Priority:		Low
Background:		NorthStar's detailed review of QRS case files identified instances in which PSEG LI provided incorrect and/or insufficient information to customers. NorthStar identified times when: ▪ PSEG LI manually calculated an incorrect credit amount ▪ PSEG LI communicated the wrong interest rate for billing overpayments ▪ CSRs resolved the DPS complaint, but did not inform customers of assistance programs or did not update the CAS with relevant information. ▪ PSEG LI did not inform qualified customers about the Household Assistance Rate Program or senior protection programs. In addition, NorthStar found that CAS entries are sometimes incorrect or incomplete and credit calculations are sometimes performed manually.
Improvements:		Provision of better information to customers and improved case documentation.
Risks:		None.
Expected Implementation Timeline:		Within six months of the issuance of the final report.
Expected Improvement Timeline:		Immediate

Cost Analysis:

Nominal.

Benefit Analysis:

There are no direct cost benefits. Implementation of this recommendation is required to comply with DPS regulations.

Payback Analysis:

NA

Recommendation XI–4 Customer Operations

Chapter(s)	Rec. #	Recommendation(s) Text
XI	4	**Modify the CTS system to improve DPS complaint tracking and reporting ability. Add data fields including:** • **The original source of complaints referred by DPS (i.e., direct from customer, Consultant, Government Official/Executive Correspondence).** • **Customer contact deadline.** • **Closeout deadline.** • **Resolution status field to differentiate between cases that are "Resolved and Closed" vs "Unresolved and Closed".** • **Indication the case is "Pending completion of future work" to allow for active follow-up.** • **Modify the Date Opened field to allow for capturing of time of day a case is created.** • **Modify Date Contacted field (default time of day set at 0:00) to force user to adjust time. Adjust internal processes to ensure data entry into this field.**
Priority:		Medium
Background:		PSEG LI tracks DPS complaints in the CTS system, a Microsoft SharePoint–based system that was not designed with DPS requirements in mind and does not allow tracking of all information required by the DPS, including the data fields listed in the recommendation above. As currently used, the CTS database cannot be used for internal reporting to determine whether Customer Relations meets all DPS QRS Requirement.
Improvements:		Inclusion of the additional data fields in CTS will allow PSEG LI to determine whether it complies with all DPS QRS requirements.
Risks:		None.
Expected Implementation Timeline:		The CTS system should be modified within six months following issuance of the final audit report.
Expected Improvement Timeline:		Tracking of requisite data will be possible upon completion of CTS system modifications.

Cost Analysis:

Nominal costs. In-house PSEG LI IT resources may be used to add fields to the SharePoint-based CTS database.

Benefit Analysis:

There are no direct cost benefits. Primary benefit is the ability to determine where PSEG LI complies with DPS requirements and internal and external reporting.

Payback Analysis:

NA

CBA 39 – Recommendation XI–5 Customer Operations

Chapter(s)	Rec. #	Recommendation(s) Text
XI	5	**Implement a Quality Assurance program in Customer Relations. Recommended items to review include:** • **Data is entered in CTS** • **CAS diary entry includes the time customer contact occurred** • **Case files are completed** • **Appropriate tools and methodology are being used to calculate adjustments** • **Consistent treatment of customers with similar issues** • **Customers complaint concerns appropriately addressed** • **DPS Complaint Response form is used to track response to DPS cases.**
Priority:		Low
Background:		PSEG LI Customer Relations personnel do not always record all case data in the Complaint Tracking System database. The only fields consistently used are "Date Closed" and DPS Closed." At times Customer Relations personnel provide incorrect or insufficient data to customers (sometimes based on manual calculations), or do not properly update CAS notes. In addition, DPS Complaint Response forms and DPS customer closeout letters are not always included in customer files.
Improvements:		Implementation of routine Quality Assurance (QA) reviews of case data and associated corrective actions will improve the quality of the case data. The case data QA review should include the case files and CTS and CAS entries.
Risks:		None.
Expected Implementation Timeline:		The Customer Relations QA program should be established within three months following the issuance of the final audit report.
Expected Improvement Timeline:		The quality of database and case file data should improve after the first or second QA review cycle. NorthStar recommends monthly reviews of files on a sample basis at the outset, followed by semi-annual reviews once the quality of data has improved.

Cost Analysis:

Nominal. Periodic QA reviews of case files on a sample basis can be performed by existing PSEG LI Customer Relations personnel. NorthStar estimates that each review (including the identification of necessary corrective actions) will take less than a day.

Benefit Analysis:

There are no direct cost benefits. Improving the quality of case data will enable more efficient review and completion of case files. It should also improve the quality of information provided to customers and ensure consistency in complaint processing and resolution.

Payback Analysis:

NA

Recommendation XII–1 External Outreach and Communications

Chapter(s)	Rec. #	Recommendation(s) Text
XII	1	**Measure the effectiveness of capital-project outreach, media relations and external affairs programs, to determine whether outreach efforts are cost-efficient, on target, and achieving results. Potential measurement options include surveys, focus groups, a media clip index, or attendance at public meetings.**
Priority:		Low
Background:		PSEG LI commissions detailed surveys on the effectiveness of its major advertising campaigns, but does not survey its constituents or measure the effective of its External Affairs activities including capital-project outreach or other proactive communication with key stakeholders. NorthStar is also not aware on any assessments of the effectiveness of ite media relations other than the review of media clips.
Improvements:		An assessment of the effectiveness of capital project outreach should identify opportunities to improve the outreach effort. Improved outreach regarding capital projects will help to mitigate potential concerns about the projects and foster PSEG LI's relationship with local government officials and citizens.
Risks:		None.
Expected Implementation Timeline:		Within six months following the issuance of the 2017 Audit Report.
Expected Improvement Timeline:		Approximately six months following the assessment.

Cost Analysis:

Estimated costs range of $100,000 for an external consultant to perform an assessment of the effectiveness of PSEG LI's media relations and capital project outreach, as well as its communications with key stakeholders, and provide recommendations to PSEG LI to improve its efforts.

PSEG LI should develop a detailed estimate of costs and include it in its audit implementation plan.

Benefit Analysis:

No direct cost benefits. More effective communications.

Payback Analysis:

NA

Recommendation XII–2 External Outreach and Communications

Chapter(s)	**Rec. #**	**Recommendation(s) Text**
XII	**2**	**On a pilot basis, evaluate the potential use and effectiveness of text messages and phone calls to customers on scheduled tree trim routes.**
Priority:		Low
Background:		PSEG LI sends letters and emails to customers two to three weeks before tree trimming begins in their neighborhoods, letting them know when work is scheduled. A door hanger is also placed on each customer's door, typically, two to three days before work starts. Customer survey results indicate that while customers are generally satisfied with the tree trimming work, most do not recall receiving a notification.
Improvements:		Use of text messages and phone calls to notify customers about tree trimming may improve customers' recollection of the notification.
Risks:		None.
Expected Implementation Timeline:		Within a year following the issuance of the 2017 Management Audit Report.
Expected Improvement Timeline:		If the pilot program proves to be effective, improvements would be realized immediately upon implementation of a text/phone call tree trimming communications program.

Cost Analysis:

The first part of the pilot program is to work with PSEG IT to determine the feasibility of using texts/phone calls to notify customers re: tree trimming activities, developing a method to target customers in specific areas, and sending texts/phone calls to customers on a sample basis.

The next part of the pilot program is to measure the effectiveness of the text/phone communications. NorthStar estimates the cost of an outside consultant to perform this analysis to range from $50,000 to $100,000.

Total Estimated Cost = $66,500 to $116,500. PSEG LI should develop a detailed estimate of costs and include it in its audit implementation plan.

Benefit Analysis:

A reduction in the labor costs associated with door hangers and customer mailings. PSEG LI should include estimated cost savings in its audit implementation plan.

Payback Analysis:

NA

Recommendation XII–3 External Outreach and Communications

Chapter(s)	Rec. #	Recommendation(s) Text
XII	3	**Measure the effectiveness of energy efficiency and low-income program outreach and marketing efforts.**
Priority:		Low
Background:		Although it performs considerable outreach, PSEG LI does not currently measure the effectiveness of its communication efforts with respect to low income programs. While not targeted at the low-income programs, various surveys and market research indicate that PSEG LI customers are not very familiar with the utility's energy efficiency programs and do not have a strong unaided recall of advertising efforts.
Improvements:		An assessment of the effectiveness of energy efficiency and low-income program outreach will identify opportunities to improve the outreach effort.
Risks:		None.
Expected Implementation Timeline:		Within a year following the issuance of the 2017 Management Audit Report.
Expected Improvement Timeline:		Approximately six months following the effectiveness assessment.

Cost Analysis:

External survey costs: $50,000 to $100,000. Reduction in usage and associated sales revenues possible. PSEG LI should develop a detailed estimate of costs and include it in its audit implementation plan.

Benefit Analysis:

Better/more effectively targeted marketing efforts which could reduce the costs of the current marketing activities. Increased market penetration and understanding of saturation levels. Potentially higher program participation. Better recall of PSEG LI's marketing efforts which could increase customer satisfaction and raise JD Power scores.

Payback Analysis:

NA

Recommendation XII–4 External Outreach and Communications

Chapter(s)	Rec. #	Recommendation(s) Text
XII	4	**Develop a more formalized process for determining the outreach budgets for capital projects, particularly Tier 3 and high scoring Tier 2 projects.**
Priority:		Low
Background:		Major capital projects are evaluated and scored as Tier 1, 2 or 3 by the External Affairs District Managers (DMs) based on perceived risk. The project justification documents (PJDs) submitted to the Utility Review Board (URB) for project approval include the External Affairs tier risk score. The tiers are used to determine the level of outreach. ▪ **Tier 1** projects are considered to be fairly straightforward; a significant external affairs strategy is generally not required. Tier 1 projects should have a fact sheet and be included in the annual briefings with officials. ▪ **Tier 2** projects are considered to have an intermediate amount of challenges and may require greater outreach. In addition to the briefing and fact sheet, Tier 2 projects should have a customer letter, website reliability page posting, a project timeline and route maps. ▪ **Tier 3** projects are considered complex and more likely to generate controversy, and as such require greater outreach. In addition to the required Tier 2 items, Tier 3 projects should have a public information session and targeted social media. External Affairs has an internal budget for its day-to-day outreach activities and direct charges or allocates outreach costs to specific projects. Each year the External Affairs team reviews the major planned capital projects budgeted for that year. Based on the outreach score, number of impacted municipalities, and experience with similar projects, External Affairs estimates the number of labor hours to be spent developing and conducting outreach for planned projects. These hours are included in the labor budget for each project. Funding requests to the URB and PJDs do not specify the outreach budget. External Affairs does not recall an instance when they have been notified that they were over budget
Improvements:		A specified budget for outreach activities for each Tier 2 and 3 capital project will enable better control over outreach expenditure.
Risks:		None.
Expected Implementation Timeline:		Within six months of the Management Audit report issuance
Expected Improvement Timeline:		Immediate

Cost Analysis:

Nominal costs. External Affairs already determines the outreach labor hours for each capital project.

Benefit Analysis:

No direct cost benefits. Improved transparency and coordination with the DPS. Better cost tracking and variance analysis.

Recommendation XII–5 Outreach and Communications

Chapter(s)	Rec. #	Recommendation(s) Text
XII	**5**	**Update the External Affairs Handbook to reflect recent lessons learned, the findings in NorthStar's report, the items cited below, and the other recommendation cited in this chapter.** ▪ **Expand the discussion of project scoring.** ▪ **For all Tier 3 projects, update constituents as the project approaches its start date, or if there are significant project changes (e.g., scope, schedule, location/route, duration, or other item likely to impact the community such as overhead versus underground, pole heights, additional poles, traffic, outages). This is in addition to the annual update on the 5-year capital plan.**
Priority:		Low
Background:		In 2014, External Affairs created a handbook and associated processes to provide a consistent, coordinated approach to outreach for capital projects. NorthStar's audit contains a number of recommendations for improvements to the External Affairs capital project outreach process. The Handbook should be updated to reflect these recommendations, changes in process or requirements, and lessons learned since the Handbook was created.
Improvements:		An updated handbook that includes lessons learned and other improvements should improve the execution of external outreach efforts.
Risks:		If the handbook is not updated, it is possible that the District Managers will not modify their processes to reflect identified improvements.
Expected Implementation Timeline:		Within a year following the issuance of the management audit final report.
Expected Improvement Timeline:		Immediate.

Cost Analysis:

Nominal costs. External Affairs budget should include hours to update the Handbook on a routine basis.

Benefit Analysis:

No direct cost benefits. Greater specificity of outreach requirements and consistency amongst the DMs.

Payback Analysis:

NA

Recommendation XII–6 External Outreach and Communications

Chapter(s)	Rec. #	Recommendation(s) Text
XII	6	**Formalize the External Affairs training and enhance it to include the following:** ▪ **Outreach expectations and requirements (e.g., frequency and information to be communicated)** ▪ **Scoring methodology and application of the scoring rubric in a consistent, objective manner** ▪ **Documentation requirements** ▪ **The External Affairs Handbook and other policies and procedures** ▪ **Communication with the DPS** ▪ **When various outreach activities/communications methods are required or should be employed** ▪ **Developing budgets for capital project outreach.**
Priority:		Low
Background:		New DMs receive training in the various systems used (i.e., geographic information system (GIS), PCall, Engines), utility operations, key departments, and external affairs-specific training covering such items as the External Affairs Handbook, the current capital project five-year plan, sample communications, the capital project scoring process and closeout, FEMA projects, vegetation management projects, municipal liaison/storm training and the IRP. New DMs also shadow experienced DMs in the field. However, the training should be formalized and updated to include changes recommended in the NorthStar audit report.
Improvements:		Formal training will help to provide a consistent approach to external outreach activities and improve PSEG LI's external outreach activities.
Risks:		None.
Expected Implementation Timeline:		Develop the training program within six months following the issuance of the management audit report. Provide training to external affairs personnel immediately following.
Expected Improvement Timeline:		Improvement should be realized shortly after training.

Cost Analysis:

Estimated costs: $50,000 - $100,000. PSEG LI should develop a detailed estimate of costs and include it in its audit implementation plan.

Benefit Analysis:

No direct cost benefits.

Payback Analysis:

NA

Recommendation XII–7 External Outreach and Communications

Chapter(s)	Rec. #	Recommendation(s) Text
XII	7	**Develop formal public outreach plans for each Tier 3 project (i.e., not a spreadsheet). At a minimum the plans should include the following, and should be updated as the project or anticipated outreach requirements change:** ▪ **Description of the project, including timeline and key milestones** ▪ **Checkpoints to identify any significant changes in project scope or timing** ▪ **Scoring sheets and a discussion of key concerns and how to mitigate them** ▪ **Discussion of alternatives considered** ▪ **Project budget and detailed outreach budgets** ▪ **Anticipated frequency of communications/timeline, planned outreach activities and materials.**
Priority:		Medium
Background:		The External Affairs District Managers work with capital Project Managers to determine outreach requirements, so that requirements are developed based on both an understanding of the project and knowledge of the community. The Public Outreach Plan required during the planning phase is effectively a checklist of the outreach activities to be completed. It does not include the items listed in the recommendation.
Improvements:		A rigorously prepared communication plan provides a coherent framework for communication actions. Documented plans will also serve as the basis for lessons learned and other operational improvements. It is crucial to produce an ongoing assessment of communication plan implementation to identify the strengths and weaknesses of the messages and the tools used. The plans should also foster coordination with the DPS.
Risks:		If PSEG LI does not develop more detailed, robust outreach plans that are more sophisticated than checklists of activities, it will not have a strong foundation for enhanced external communications.
Expected Implementation Timeline:		Immediate
Expected Improvement Timeline:		Improvements in capital project outreach efforts will be realized following the development of plans.

Cost Analysis:

Nominal costs as District Managers currently have responsibility for the development of external communications plans.

Benefit Analysis:

No direct cost benefits.

Payback Analysis:

NA

Recommendation XII–8 External Outreach and Communications

Chapter(s)	Rec. #	Recommendation(s) Text
XII	8	**Document meetings (date, attendees, topics discussed, and takeaways) with impacted officials as required by the External Affairs Handbook.**
Priority:		Low
Background:		Although required by the External Affairs Handbook, PSEG LI does not consistently take notes “memorializing” meetings/briefings with impacted officials..
Improvements:		Consistent documentation of meetings with impacted officials will provide information to evaluate best practices and lessons learned. Ensure meeting takeaways have been documented so follow-up action can be taken as needed.
Risks:		
Expected Implementation Timeline:		Immediate
Expected Improvement Timeline:		It will take some time to see the impact on PSEG LI’s public image and relationships with government officials.

Cost Analysis:

No significant costs as this is fulfilling an existing requirement.

Benefit Analysis:

No direct cost benefits.

Payback Analysis:

NA

Recommendation XII–9 External Outreach and Communications

Chapter(s)	**Rec. #**	**Recommendation(s) Text**
XII	9	**Increase the specificity of capital project-related outreach:** ▪ **Include more specific, detailed project information on public information meeting letters and notices.** ▪ **All outreach materials (i.e., fact sheets and customer letters) resulting in additional poles, pole changes, a shift from underground to overhead cables should indicate such and provided detailed description.** ▪ **Consider increased use of pictures and renderings in outreach materials, particularly the reliability web pages.** ▪ **Add a link to PSEG LI's reliability web page on all outreach materials, particularly customer letters. Include dates materials were added to the reliability project pages of PSEG LI's website.** ▪ **Consider an icon for "Upcoming projects in your neighborhood" or the equivalent to the www.psegliny.com landing page.** ▪ **Include community/public meeting presentations on the reliability pages of PSEG LI's website.**
Priority:		Low
Background:		PSEG LI's capital project outreach program may not provide adequate information regarding higher risk capital projects. Public meeting/open house notices are generic and do not provide customers with details of the project. Letters to affected customers are based on a standard template. ▪ Letters do not include a link to the reliability portion of PSEG LI's website. ▪ Letters do not consistently provide customers with specific details regarding when construction will occur or the details on road closures and traffic issues. ▪ Letters do not include maps, schematics, pictures or illustrations, and the level of detail varies. Letters and fact sheets do not consistently include the heights of existing or new poles. PSEG LI's website provides more details regarding the PSEG LI reliability projects; however, this information is not advertised and is not easy to locate.
Improvements:		Including project-specific details in outreach communications and facilitating access to project information on PSEG LI's website will increase the public's awareness and understanding of the projects, and could improve PSEG LI's relationship with the community.
Risks:		None.
Expected Implementation Timeline:		Within six months of management audit report issuance. Changes to the PSEG LI website should be made the next time the website is updated.
Expected Improvement Timeline:		Immediate.

Cost Analysis:

Nominal costs as External Affairs currently develops outreach materials. Implementation of this recommendation might require the DMs to update standard communications with additional, project-specific information.

Recommended changes to PSEG website should be made as part of the next LI website update.

Benefit Analysis:

No direct cost benefits.

Payback Analysis:

NA

Recommendation XIII–1 Performance Management

Chapter(s)	Rec. #	Recommendation(s) Text
XIII	1	**Develop and adhere to a schedule for completion of the annual metric identification and target setting process that provides for a final list of approved metrics at the beginning of the measurement year. Tier 1 Metrics, definitions, weightings and targets should be set no later than February 28. There should be a final sign-off on all of the aforementioned elements. Note: This is not intended to imply that the metric book must be completed by February 28; however, it should be done in an expeditious manner.**
Priority:		Medium
Background:		There is no required timeframe for determination of the metrics and targets, and there was no formal sign-off until the 2017 metric negotiation process. ▪ 2016 metrics were presented to the BOT Contract Oversight Committee on March 21, 2016. The final OSA Metrics and Targets Book was not finalized until mid-2016. ▪ Discussion of 2017 metrics began in September 2016. Revisions to the JD Power targets were still being considered when half the survey results had been reported. The 2017 metrics were presented to the BOT Oversight Committee on March 29, 2017. The targets were officially finalized and signed off on August 16, 2017. Metrics should ideally be finalized before the beginning of the new measurement cycle, and no later than the first quarter of the new cycle.
Improvements:		Tier 1 metrics, definitions, weighting and targets will be finalized with little information about actual performance results
Risks:		If targets are not finalized early in the year, it is possible that actual results to-date could influence the determination of metrics, definitions, weighting and targets.
Expected Implementation Timeline:		Implementation should be begin with the determination of 2019 Tier 1 metrics
Expected Improvement Timeline:		Immediate upon implementation.

Cost Analysis:

No significant incremental costs.

Benefit Analysis:

No direct cost benefits.

Payback Analysis:

Not applicable.

Recommendation XIII–2 Performance Management

Chapter(s)	Rec. #	Recommendation(s) Text
XIII	**2**	**PSEG LI and LIPA should streamline its process to facilitate the establishment and measurement of meaningful operational metrics to monitor performance, incorporating DPS staff input, and potentially bifurcating the Tier 2 metrics. This might expedite the finalization of the Tier 1 metrics. Examples include:** ▪ **Establish a smaller group of Tier 2 metrics used to test metrics for possible inclusion as a Tier 1 metric or to continue to monitor performance when a Tier 1 metric has been moved to a Tier 2 metric.** ▪ **Establish a separate classification of metrics to be used to monitor performance in specific areas or for operational reporting. These metrics would not be tied to compensation and could then be used to address such items as the following:** - **Changes in regulatory requirements or NYS initiatives (e.g., Reforming the Energy Vision, Clean Energy)** - **Elements of LIPA's Strategic Plan, Utility 2.0 or the IRP.** - **AMI implementation status** - **Issues identified by internal or external audits, including performance deficiencies identified by NorthStar's audit.** - **Operational changes or revised priorities.** - **Tracking new initiatives or sub-elements of existing initiatives.** - **Metrics intended to address efficiency and effectiveness.** - **As examples, a number of the Tier 2 metrics used over time would more appropriately have been part of this category: social media followers, staffing levels permanent, percent of financial management reports delivered to LIPA.**
Priority:		Medium
Background:		Although there have been changes in both the Tier 1 and Tier 2 metrics over time, changes must be agreed to by both parties. PSEG LI has met or exceeded most of its Tier 1 incentive metrics. Adjusting a performance metric is a multi-step process. According to the Contract Administration Manual (CAM) Procedure BPE-F1: ▪ Either PSEG LI or LIPA, or both, may recognize a need to amend or adjust one or more performance metrics regardless of tier assignment. Potential causes include evolving business conditions, force majeure, LIPA fault, other reasonably unanticipated events or additional LIPA regulatory needs. ▪ PSEG LI forms working groups to collect data and analyze the impacts. Recommendations are reviewed internally and then by the PSEG LI management team to identify an optimal solution. ▪ A proposal is presented to LIPA subject matter experts. ▪ PSEG LI and LIPA review and finalize the metrics or changes based on mutual agreement. LIPA/PSEG LI also solicit input from DPS. ▪ LIPA submits the proposal to the Management Review Board (MRB). The MRB discusses the proposal internally and with the PSEG LI/LIPA teams. The MRB determines whether to accept or reject the LIPA proposal.

	▪ If the proposal is rejected by the MRB, the PSEG LI Management Team must determine whether to accept the decision and forego discussed modifications or to formally dispute the proposal, in accordance with the dispute resolution process laid out in Section 8.6 of the A&R OSA.
Improvements:	Streamlining the process to facilitate the establishment and measurement of meaningful operational metrics will help to expedite the finalization of the Tier 1 metrics and drive continuous process improvement.
Risks:	None
Expected Implementation Timeline:	Q3 2018 – Prior to the determination of the 2019 Tier 1 metrics.
Expected Improvement Timeline:	Immediate upon implementation

Cost Analysis:

No significant incremental costs.

Benefit Analysis:

No direct cost benefits. Should drive performance improvements.

Payback Analysis:

Not applicable.

Recommendation XIII–3 Performance Management

Chapter(s)	Rec. #	Recommendation(s) Text
XIII	3	**LIPA and PSEG LI should continue to evaluate how to best incentivize service provider performance (Tier 1 metrics), drive continuous improvement and align the metrics with the focus of LIPA and PSEG LI's long-term strategy/operational needs and industry best practices.**
Priority:		Medium
Background:		The Tier 1 metrics have been consistently achieved. Since the beginning, PSEG LI has significantly exceeded many of the metric targets.
Improvements:		Implementation of this recommendation should result in improved operational performance and alignment with LIPA/PSEG LI's long-term strategy, and the industry.
Risks:		None.
Expected Implementation Timeline:		Q3 2018 – Prior to the determination of the 2019 Tier 1 metrics.
Expected Improvement Timeline:		Immediate upon implementation

Cost Analysis:

No significant incremental costs.

Benefit Analysis:

Should result in performance improvements. Any cost savings cannot be quantified at this time. Benefits will be dependent on the nature of the metric.

Payback Analysis:

Not applicable.

Recommendation XIII–4 Performance Management

Chapter(s)	**Rec. #**	**Recommendation(s) Text**
XIII	**4**	**Define the metric calculation methodology to specify whether service restorations completed in exactly two hours should be included in the ETR Accuracy performance metric. NorthStar found the specified calculation methodology open to some interpretation. Currently, PSEG LI does not include restoration times of exactly two hours. This should be reconciled between PSEG LI and LIPA.**
Priority:		Low
Background:		NorthStar's metric testing found that when calculating the Estimated Time to Restore (ETR) Accuracy metric, PSEG LI does not consider that it has completed restoration *within* 2 hours when it completed the restoration in *exactly* 2 hours. The language of the Performance Metric is unclear as to whether these observations should or should not be included. This should be reconciled between PSEG LI and LIPA.
Improvements:		Implementation of this recommendation will improve the accuracy of the ETR Accuracy performance metric.
Risks:		Absent implementation of this recommendation, there will continues to be questions regarding how to treat service restorations that are completed in exactly 2 hours in the ETR Accuracy performance metric
Expected Implementation Timeline:		Determine how to treat service restorations that are completed in exactly 2 hours in the ETR Accuracy performance metric as part of the negotiation of metrics and targets for 2019.
Expected Improvement Timeline:		Immediate following implementation

Cost Analysis:

No incremental costs.

Benefit Analysis:

No direct cost benefits. The primary benefit associated with this recommendation is more accurate reporting of ETR Accuracy performance metric.

Payback Analysis:

NA

Recommendation XIV–1 Fuel and Purchased Power

Chapter(s)	Rec. #	Recommendation(s) Text
XIV	1	**Memorialize the process regarding PSEG LI conflict of interest in regional market activities (discussed in Section 4.18 of the A&R OSA) in the Contract Administration Manual (CAM).**
Priority:		Low
Background:		There are times that that PSEG LI cannot take the lead in advocating an issue at a Regional Transmission Organization (RTO), such as NYISO or PJM, due to potential conflicts with Public Service Enterprise Group or any of its affiliates. In such cases, LIPA takes the lead and PSEG LI typically is silent on the issue. There are no documented policies or procedures that address conflicts of interest. The OSA acknowledges that PSEG LI's representation of LIPA before regulatory or industry parties may give rise to conflicts of interests, but there is not a procedure or formal guidance regarding steps to ensure an issue does not pose a conflict of interest and steps to take once a conflict is identified.
Improvements:		Formal procedure regarding the determination of PSEG LI conflicts of interest and its actions in the event of a conflict.
Risks:		If conflicts of interest are not identified and PSEG LI remains involved in RTO discussions regarding an issue, it is possible it will not act in the best interest of LIPA and its ratepayers.
Expected Implementation Timeline:		Within three months of the issuance of the final report.
Expected Improvement Timeline:		Upon implementation and ongoing.

Cost Analysis:

There are nominal incremental costs to develop a procedure to address PSEG LI conflict of interest in regional market activities on the following assumptions:

<u>One-Time Labor Costs</u>
30 hours to develop procedure and obtain necessary approvals.
Average fully loaded labor costs estimated to be $100/hour.
Total costs: $100/hour X 30 hours = $3,000.

Benefit Analysis:

While a formal procedure will improve efficiency of the process to identify PSEG LI conflicts of interest in RTO markets, there are no direct cost benefits.

Payback Analysis:

NA