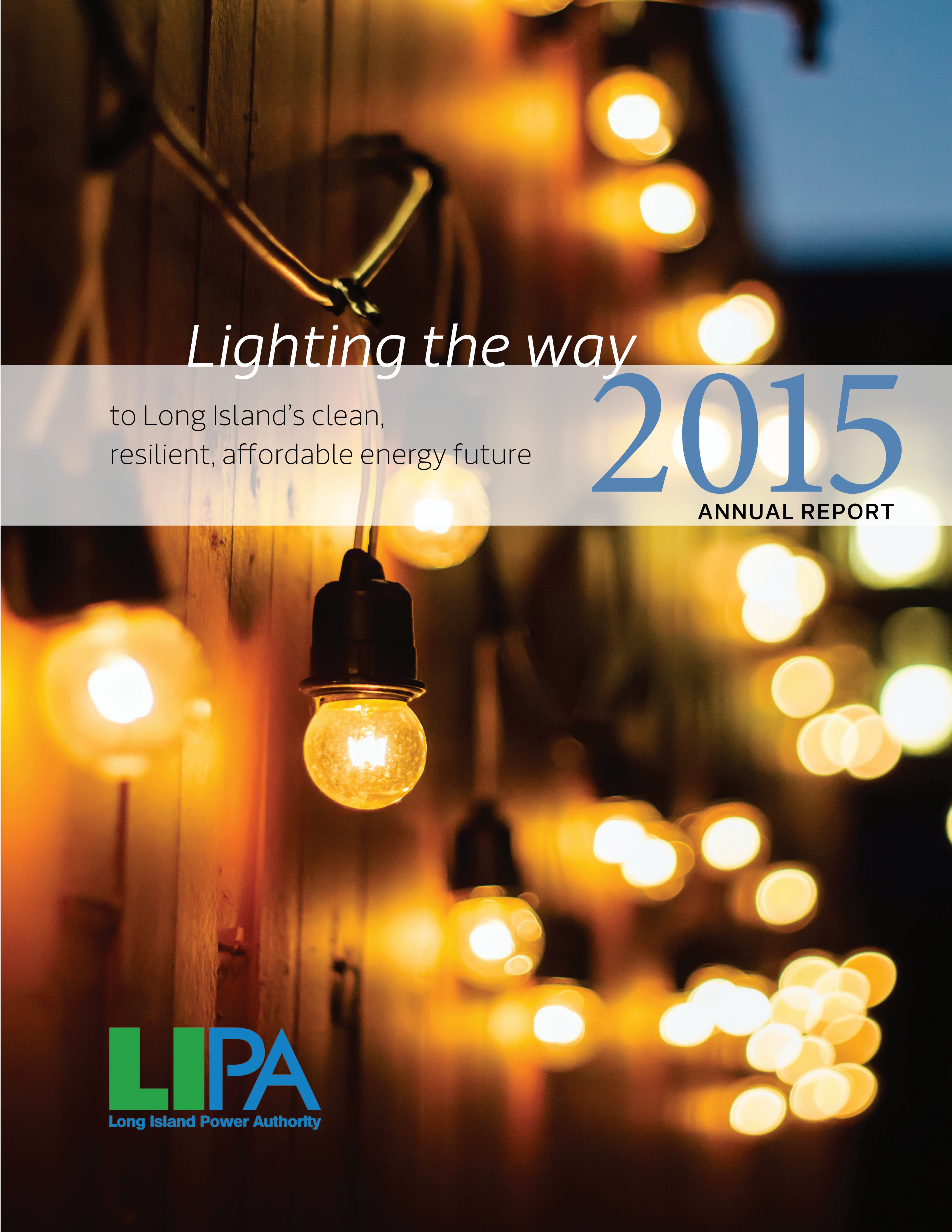

Lighting the way

to Long Island's clean, resilient, affordable energy future

2015 ANNUAL REPORT

LIPA
Long Island Power Authority

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Dear Fellow Customers and Stakeholders:

Each year, the Long Island Power Authority ("LIPA") reports on the progress of your utility. This year's report will describe some of the significant developments at LIPA since the LIPA Reform Act of 2013, including our efforts to:

- improve customer service and satisfaction,
- maintain high electric system reliability and improve emergency response and storm resiliency,
- continue our investment in clean energy and energy efficiency,
- increase the transparency of LIPA's costs and electric rates, and
- reduce the legacy burden of debt and taxes on our customers.

LIPA has made progress in each of these areas over the last two years while maintaining our role as Long Island's not-for-profit, publicly owned electric utility — providing service to our customers at a system average electric rate as much as 30 percent below those of neighboring utilities.

Improving Customer Service and Satisfaction

The most important change for our customers over the last two years has been LIPA's transition to a new service provider — PSEG Long Island, who operates the Long Island electric system on LIPA's behalf under its own local brand. PSEG Long Island was formed from its sister company, PSE&G, one of the largest utilities in the nation and one with an outstanding record of customer service in its own service territory[1]. This new contractual arrangement provides transparency and the direct accountability of our service provider to our customers. LIPA and PSEG Long Island have put in place operational and customer service improvement goals for the first five years of our contract. These goals determine how PSEG Long Island allocates its time and resources and — importantly — the amount we pay PSEG Long Island for managing the LIPA electric system each year[2].

PSEG Long Island Is Delivering Customer Service Improvements

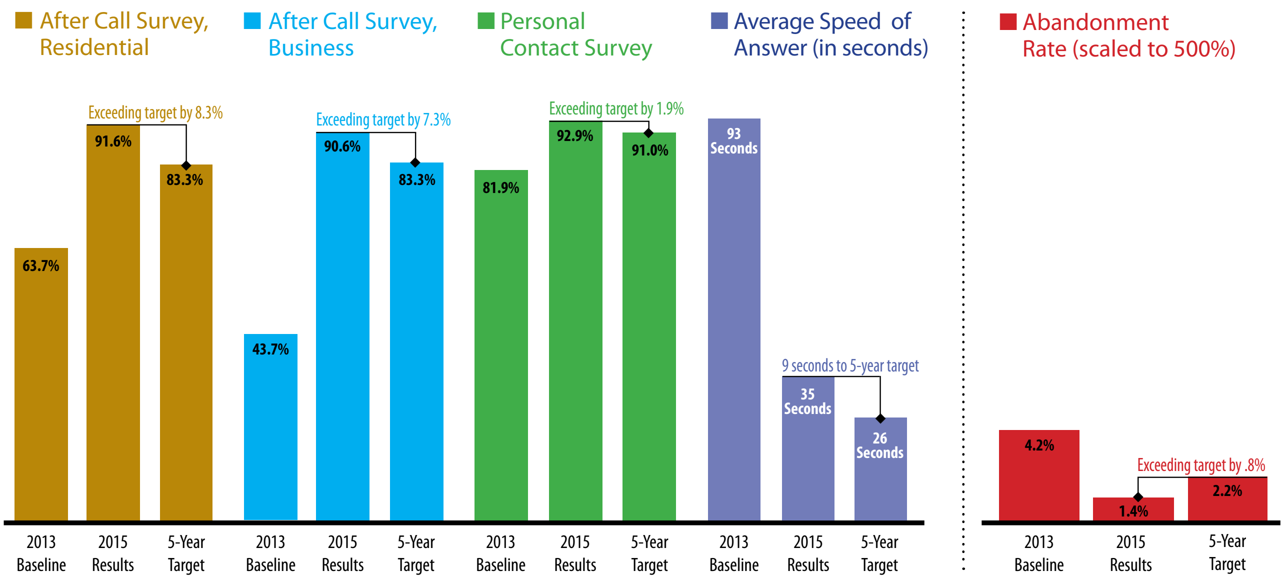
In the first two years of operations under our new contract, PSEG Long Island achieved 90 percent and 86 percent of our overall performance goals, respectively. The utility has renovated and opened new customer service offices, increased call center staffing at peak times, reduced average call waiting times, introduced new information technology to improve customer communication and outage tracking, and focused on serving our local Long Island community.

1 PSE&G is ranked #2 in the 2015 J.D. Power Residential Utility Customer Satisfaction Survey, East Large Segment, with a score of 680.

2 PSEG Long Island is reimbursed its prudently incurred costs for running the LIPA electric system and paid a management fee with performance incentives for its services.

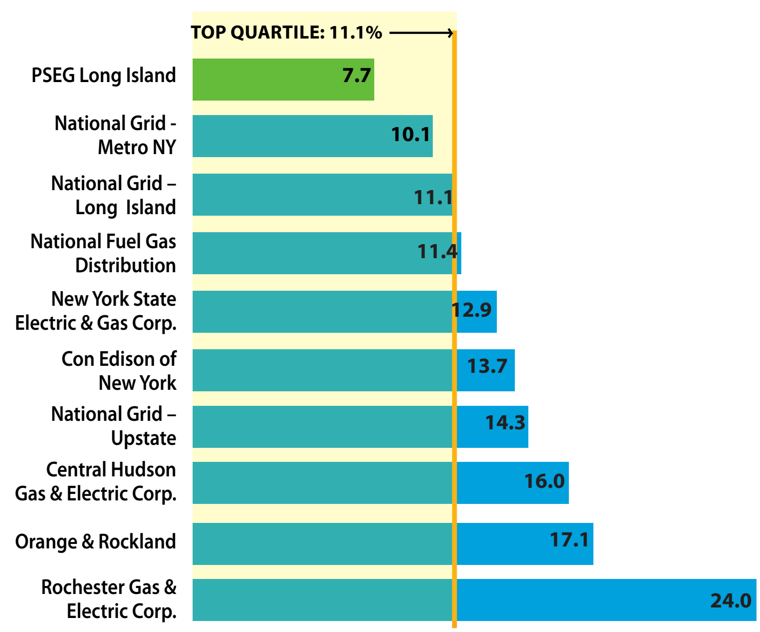
Our customers are noticing these initiatives. On four of the five key customer satisfaction indicators summarized in Chart 1 below, PSEG Long Island has not only significantly improved from the 2013 benchmark levels under our prior service provider, they actually moved to among the best performing utilities in the industry — meeting or exceeding their fifth-year performance targets in only the second year of operations.

Chart 1: Key Measures of Customer Service 2013 vs. 2015



Another broad measure of customer satisfaction is PSEG Long Island's initial customer complaint rate per 100,000 customers. Under the LIPA Reform Act, the New York State Department of Public Service ("DPS") now independently oversees customer complaints on Long Island to ensure the fair resolution of issues. Notably, during 2015, PSEG Long Island's initial customer complaint rate declined approximately 26 percent from the prior year and was the lowest of any of the New York utilities, as shown in Chart 2.

Chart 2: 2015 Initial Customer Complaint Rate Per 100,000 Customers



Source: Department of Public Service; rolling 12 months ending December 2015

Additionally, the surveys of electric utility customers conducted by J.D. Power and Associates have reflected these trends. In fact, PSEG Long Island is among the most improved utilities anywhere in the nation over the last two years — starting from a residential customer survey benchmark score of 519 in 2013 and rising to 532 in 2014 and 584 in 2015. Furthermore, PSEG Long Island and LIPA have agreed to target additional increases in customer satisfaction over the next three years. There is still more to do, but your Long Island electric utility is focused on improving customer service, and we are making progress.

Maintaining High Electric System Reliability and Improving Emergency Response and Storm Resiliency

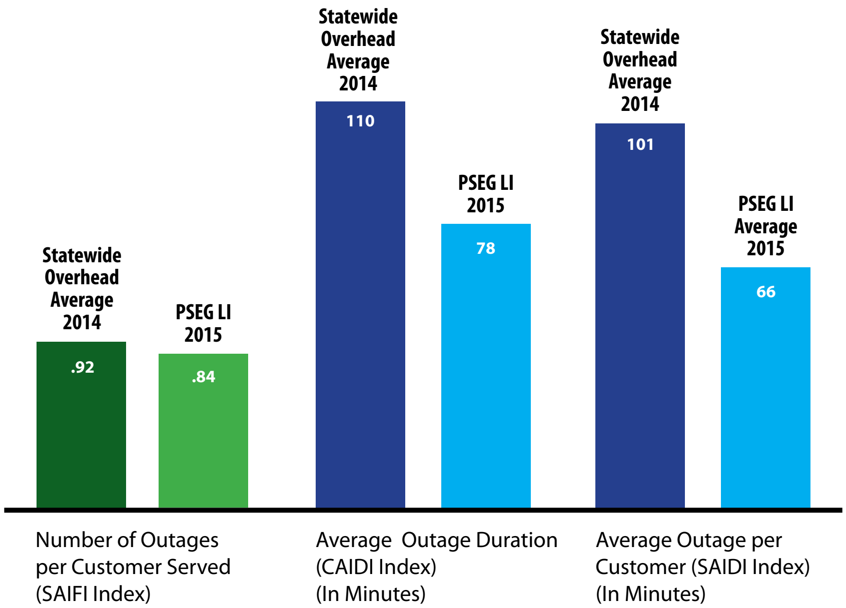
There are a number of factors that go into maintaining a reliable overhead electric system, including good system design, sound and well-funded maintenance programs, regular tree trimming and pole inspections, and adequate ongoing infrastructure investment. Work force levels, deployment of crews during electric outages, and geography also influence measures of reliability. Decisions made today can take several years to impact reliability, so it is important to avoid meeting near-term cost pressures in ways that could hurt long-term reliability. As one utility industry veteran said in another context, "someone is sitting in the shade today because someone planted a tree a long time ago."

Over the last two years, PSEG Long Island has maintained the highest level of day-to-day system reliability of any overhead New York utility[3] as measured by industry benchmarks,[4] levels that would place it among the top 25 percent of utilities in the country. In 2015, on average, each Long Island customer experienced less than a single electric outage (0.84 outages per year) (SAIFI Index), with outages lasting on average 78 minutes (CAIDI Index). Multiplying these two statistics, on average, each customer was without power for only 66 minutes (SAIDI Index) during 2015, compared to an average for New York overhead utilities in the most recently available report of 101 minutes per year, as shown in Chart 3 on the following page.

3 Sources: PSEG Long Island; New York Department of Public Service 2014 Electric Reliability Performance Report, June 2015.

4 The System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and System Average Interruption Duration Index ("SAIDI") are commonly used reliability metrics for electric utilities.

Chart 3: PSEG Long Island is the Most Reliable Overhead Utility in New York

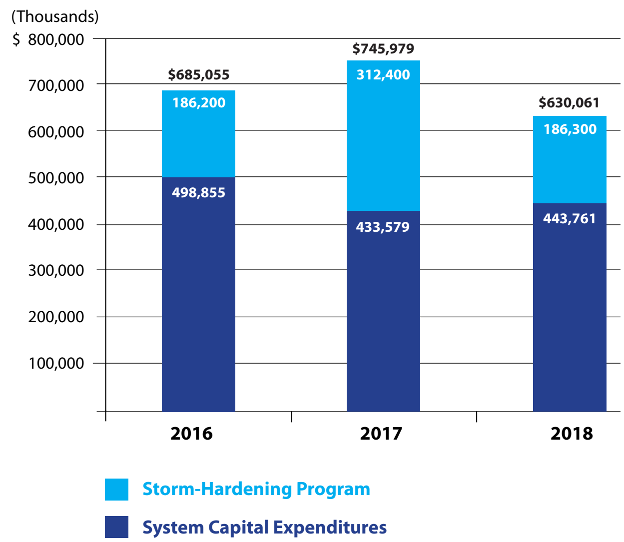


Source: PSEG Long Island 2015; Department of Public Service 2014 Electric Reliability Report, June 2015; excludes major storms

Record $2 billion 3-Year Infrastructure Investment and $730 Million Storm-Hardening Program

To maintain today's high levels of reliability, improve customer service, and enhance the resiliency of the electric system to severe storms, the LIPA Board of Trustees approved a record capital investment program for the next three years — $2+ billion, roughly double the historic level of investment (see Chart 4). The centerpiece of this plan is a $730 million storm-hardening program that will harden close to 1,000 miles of Long Island's electric circuits, raise ten at-risk substations above projected flood levels, and add nearly 1,300 new automated switches that allow service interruptions to be isolated and minimized. Importantly, with the help of Governor Cuomo, LIPA secured a federal grant to fund 90 percent of the cost of this $730 million storm-hardening investment — allowing LIPA to accelerate our investment for improved system resiliency while minimizing the cost to our customers.

Chart 4: $2 Billion 2016-2018 Infrastructure Investment Plan



PSEG Long Island Has Improved Emergency Response

Improving emergency response is another core goal of the LIPA Reform Act, and the best way to improve a utility's response to an emergency is to be prepared before the storm comes. Preparing for storms means investing in our electric system and maintaining adequate staffing levels to respond to an emergency but also includes the plans and processes in place long before a storm occurs.

In the last two years, PSEG Long Island has undertaken a number of efforts to improve emergency response. These include a new Emergency Response Plan ("ERP"), which is now reviewed annually by the DPS; and installation of a modern outage management system, improving the utility's ability to track customer outages and communicate with those who have lost power. During a major event, communication to all of our stakeholders is critical, and PSEG Long Island's ERP now deploys liaisons directly to county, city and state Emergency Operations Centers. In addition, PSEG Long Island has developed a Municipal Portal that allows local governments on Long Island to communicate directly with the utility on critical facilities and clearing road debris. The ERP also includes a Flood Assessment Command Center whose sole purpose is to coordinate all activities associated with flood assessment, disconnection and reconnection of electrical service due to severe widespread flooding, which was an issue after Superstorm Sandy.

No level of preparation will eliminate the effects of a truly devastating weather event. Mother Nature can overwhelm the best of plans. However, Long Island is more prepared today than two years ago and has significant additional storm-hardening investments planned over the next three years.

Continuing Our Investment in Clean Energy and Energy Efficiency on Long Island

Our customers want access to cleaner, more efficient, and renewable energy. LIPA has long-supported these goals in a number of ways, including offering rebates and incentives for customer-sited photovoltaic ("PV") solar systems, net metering self generation, instituting an ambitious ten-year energy efficiency program, and directly procuring energy from renewable sources. In 2014, LIPA transitioned from its own solar rebate program to the statewide NY-Sun program, which increased the funding available for solar rebates and accelerated the adoption of PV solar systems on Long Island. This change allowed Long Island to reach a milestone with the 10,000th PV solar system installed on our electric grid in 2014, a goal more than 14 years in the making. And the pace of change has accelerated — with LIPA reaching 20,000 solar systems a little more than a year later. Our Efficiency Long Island ("ELI") program, instituted in 2009, also remains on target to achieve its goals. ELI seeks to reduce peak load on Long Island by 520 megawatts — roughly the equivalent of one-and-a-half new power plants — by 2018.

Chart 5 below shows the progress of our PV solar and energy efficiency programs over the last two years. PSEG Long Island has met or exceeded our goals for load reduction — 71 megawatts in 2014, 16 percent over target, and 81 megawatts in 2015, 21 percent over target. And, as shown in Chart 6, we remain on track to achieve our 520 megawatt goal for peak load reduction by 2018.

Chart 5: Efficiency Long Island and Renewable Energy Load Reductions Since 2013

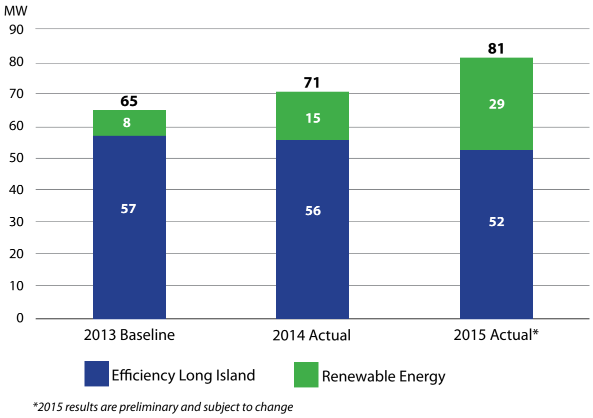
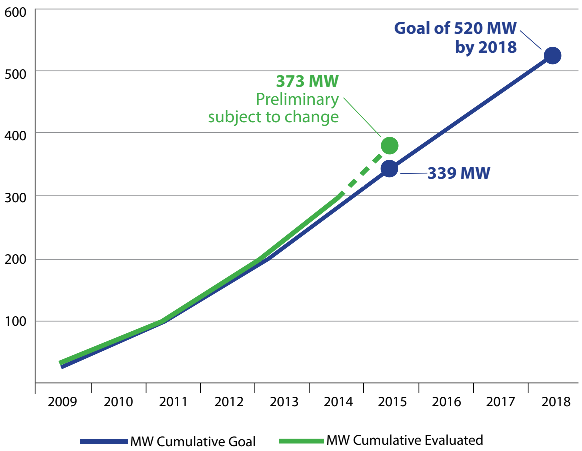


Chart 6: Efficiency Long Island and Renewable Energy Progress Toward 2018 Load Reduction Goal



In addition, over the last two years, the LIPA Board of Trustees has approved the procurement of over 200 megawatts of renewable energy projects on Long Island, which are now in various stages of environmental permitting and construction. In late 2015, PSEG Long Island announced an additional solicitation for 210 megawatts of renewable energy, with proposals due in mid-2016 for commercial operation dates no later than 2022.

Innovation in the Electric Industry and on Long Island

New technology and the falling cost of renewable energy are offering electric utilities opportunities to be innovative in ways that enhance customer participation, utilize market forces, and promote system efficiency. The New York State Public Service Commission ("PSC") commenced the Reforming the Energy Vision ("REV") proceeding in April 2014 to encourage these developments among New York's investor-owned utilities, and similar experimentation and innovation is underway on Long Island. In 2015, LIPA and PSEG Long Island undertook several such initiatives, including:

- a market solicitation to explore opportunities to cost-effectively defer transmission investment on the South Fork of Long Island using energy efficiency, demand response, and distributed energy solutions;

- a dynamic load management program using direct load control devices, advanced metering, and performance payments to cost effectively reduce distribution system investment otherwise needed to meet peak energy usage across Long Island[5];
- a community net metering program to allow small customers to share the output of larger distributed clean energy generation, thereby both expanding access to clean energy and reducing cost; and
- the expansion of our advanced metering network across Long Island, a prerequisite to providing customers with greater information, innovative pricing, and new opportunities to control their energy usage.

Increasing the Transparency of LIPA's Costs and Electric Rates

The LIPA Reform Act introduced a new transparent process to review LIPA's cost to provide safe and reliable utility service and thereby determine electric delivery rates. That process incorporates public participation as well as independent review and recommendations from the DPS, the staff arm of the state PSC. LIPA and PSEG Long Island initiated this new process for the first time on January 30, 2015 with the filing of a Three-Year Rate Plan for 2016-2018 (the "Rate Plan"). Under the guidance of two DPS administrative law judges over eight months, the Rate Plan was the subject of exhaustive data exchange, cross examination, and briefing by 11 parties — a process consistent with that used for the review of rate filings by New York's investor-owned utilities. The record in the rate case included over 1,500 transcript pages, 140 separately marked exhibits, and 1,850 comments from members of the public. This review, with the direct involvement of the utility professionals of the DPS staff, added a layer of third-party diligence in analyzing our costs and operating practices that should provide our customers and stakeholders with confidence that our electric rates are at the lowest levels consistent with sound fiscal and operating practices.

The Rate Plan recommended by the DPS and approved by our Board in December 2015 includes a 0.5 percent adjustment to total charges in 2016, 2.0 percent in 2017, and 2.0 percent in 2018. Importantly, these rate adjustments follow a three-year delivery rate freeze, and therefore result in average rate increases of less than one percent per year over the six-year period beginning in 2013, less than the rate of inflation.

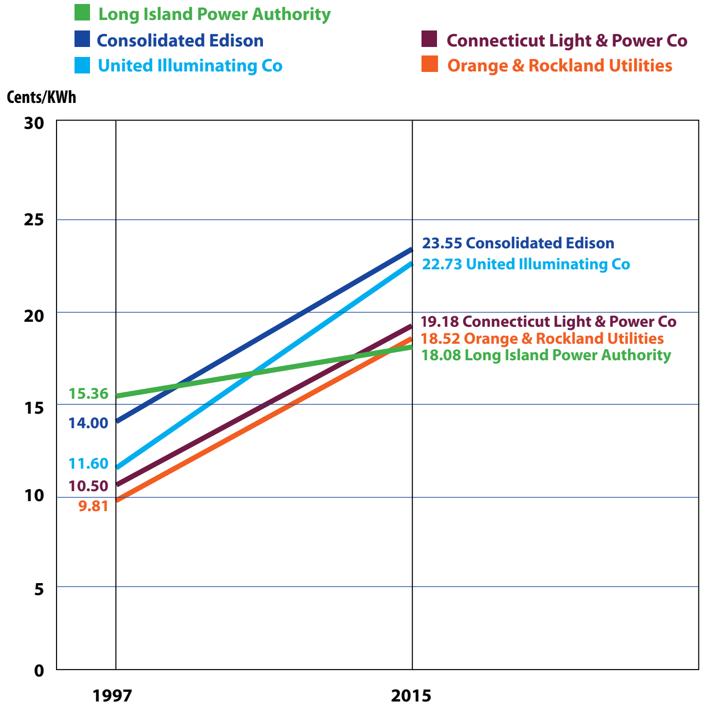
Record of Moderate Rate Adjustments for our Customers

As a publicly-owned electric utility, LIPA's electric rates reflect its costs to provide service with no profit margin. Since 1998, LIPA's electric rates have increased by approximately 18 percent, while the consumer price index has increased by 47 percent, and the rates of other regional electric providers have increased by as much as 96 percent.

5 Proposed in 2015 and approved by the LIPA Board of Trustees on March 21, 2016.

LIPA's goal is for its electric rates to remain competitive with those of the other regional utilities facing similar costs and fuel/power supply options. As shown in Chart 7, over the last 18 years since the LIPA acquisition of the Long Island Lighting Company ("LILCO"), LIPA has gone from having the highest electric rates in the region to among the lowest, albeit in a region with above average costs. Of note, as also shown in the chart, our electric rates are up to 30 percent below those of our neighboring utilities in southern New York and Connecticut, which are the utilities that face the most similar costs of doing business to those of LIPA.

Chart 7: Regional System Average Electric Rates Since 1997



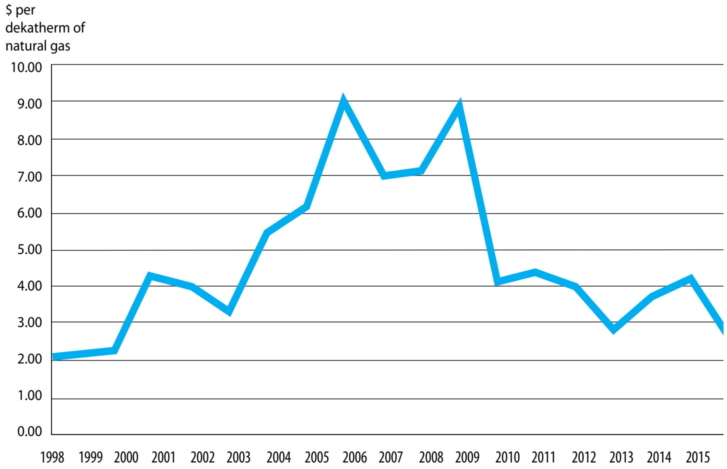
Source: U.S. Energy Information Administration form 826

Falling Natural Gas Prices Reduced Customer Bills on Long Island in 2015

The Three-Year Rate Plan described above determined LIPA's charges for delivery service. However, like other New York utilities, LIPA's customers pay our actual fuel and purchased power costs — no more and no less — through a Power Supply Charge that adjusts each month.

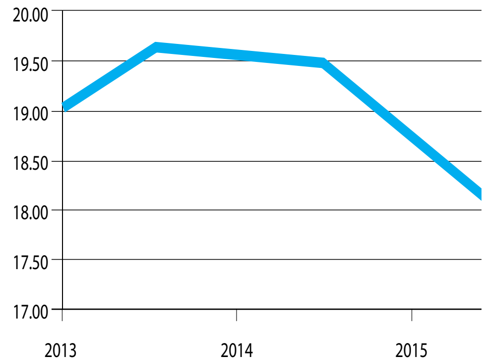
LIPA's generation fuel is predominantly natural gas. An important trend in LIPA's costs, and therefore its electric rates, has been the dramatic decline in natural gas prices, which as shown in Chart 8 are now back to late 1990s levels — falling from a high of $9 per decatherm ("Dth") in 2005 to an average of $4.25/Dth in 2014 and $2.60/Dth in 2015. That decline has lowered electric bills for our customers. As shown in Chart 9, our system average rate in 2015, including delivery charges, was 18.0 cents per kilowatt-hour — 7% lower than 2014 and the lowest annual average since 2007.

Chart 8: Natural Gas Prices are Back to 1998 Levels



Source: NYMEX Henry Hub, annualized averages by year

Chart 9: LIPA System Average Rates Have Declined Since 2013 (Delivery and Power Supply Charges)

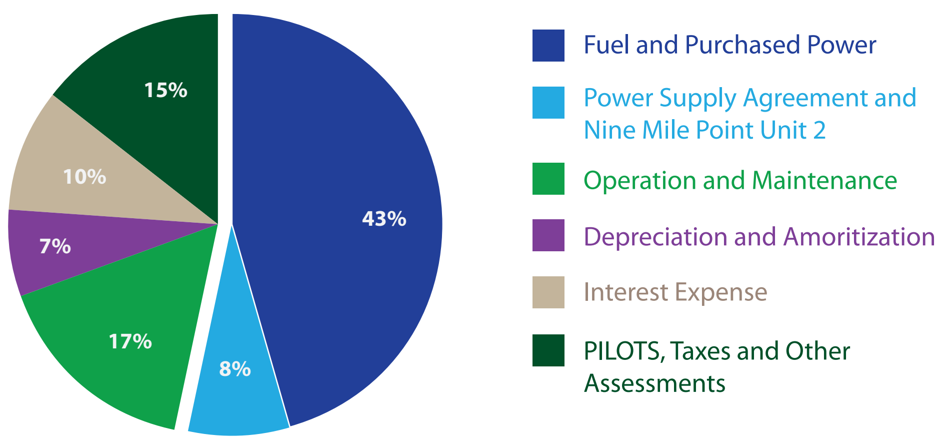


Reducing the Legacy Burden of Debt and Taxes on Customers

"In this world nothing can be said to be certain, except death and taxes."—Benjamin Franklin

Substitute the word "debt" and some on Long Island might think Benjamin Franklin's statement applies to their electric utility. Interest on debt and taxes are approximately 25 percent of every dollar LIPA spends — our third and fourth largest cost categories after fuel and purchased power expenses (51 percent, including the Power Supply Agreement and Nine Mile Point Unit 2), and operations and maintenance (17 percent) (see Chart 10 below). Since the LIPA Reform Act, LIPA is attempting to better manage these two costs, leaving more funds available for our customers' priorities like customer service, reliability, and clean energy.

Chart 10: Operating and Interest Expenses



Why LIPA Issues Debt

LIPA has a unique history as a not-for-profit public power utility, having acquired the for-profit LILCO for $6.295 billion in May 1998 in a transaction principally funded by tax-exempt municipal bonds. Together with assumed debt and debentures and the funding of credits and capital expenditures, LIPA closed its first year of operations with $7.95 billion of long-term debt. The bonds issued to acquire LILCO were scheduled to be repaid similar to a home mortgage, with principal and interest payments in each year over 35 years ending 2033. The purchase of LILCO provided an immediate benefit to Long Island customers — a 20 percent reduction from LILCO's electric rates — that was possible due to LIPA's not-for-profit status, lower cost of capital, exemption from corporate income taxes, and access to low cost tax-exempt bonds. The purchase of LILCO also left LIPA with a high debt burden compared to other utilities — one scheduled to be paid down over 35 years.

LIPA has periodically refinanced the debt issued to acquire LILCO to reduce cost, but the payment schedule remains the same. That debt will be entirely gone in 2033. However, in each year, LIPA funds a large investment plan — $685 million in 2016 and over $2 billion through 2018. Those investments are in physical assets that are necessary to deliver electricity to our customers over the next 50+ years. As a utility owned by the public, there are only two sources of funds for those investments — electric rates and debt[6]. Used prudently, debt is a tool that can appropriately spread the cost of infrastructure investments over the useful life of the assets, ensuring that today's customers pay some of the cost and that future customers, who also benefit from today's investments, pay an appropriate share of the cost too. Used imprudently, debt can burden future customers with higher costs than their fair share.

Recent Actions to Reduce the Cost of LIPA's Debt for Customers

LIPA's relatively high debt level has left it with lower "triple-B" credit ratings. Due to those lower credit ratings, investors expect LIPA to pay higher interest rates than other better-rated electric utilities. The LIPA Reform Act authorized a series of debt issues through a newly formed state agency to refinance roughly 60 percent[7] of LIPA's higher cost "triple-B"-rated debt with lower cost "triple-A" rated bonds. Our current estimate is that this refinancing, when complete, will save customers over $435 million in lower interest costs over the life of the refinanced bonds.

In addition to reducing the cost of already outstanding debt, the LIPA Board of Trustees adopted a new financial policy in December 2015 that was endorsed by the DPS in our Three-Year Rate Plan filing. As the new Board policy states:

> *"It is the policy of the Board of Trustees of the Long Island Power Authority to serve the long term interests of our Customers by adopting sound financial plans in each year… Such plans contain prudent levels of borrowing and lower the long-term cost of providing electric service to our Customers."*

6 As a public power utility, LIPA is also sometimes eligible for federal grants like those described above to fund 90 percent of the cost of our $730 million storm-hardening program.

7 The LIPA Reform Act authorized the sale of up to $4.5 billion of Utility Debt Securitization Authority bonds.

The cornerstone of that new financial policy is to ensure that new bonds fund no more than 64 percent of LIPA's annual capital spending. That is accomplished by increasing the portion of LIPA's infrastructure investment that is funded by internal cash flow, while reducing the portion that is debt funded. This financial policy is designed to raise LIPA's credit ratings over a five-year period, thereby further reducing the cost of LIPA bonds for customers. According to recent credit reports by Fitch Ratings[8], this financial policy "provides sound long-term financial goals and policies," "should moderate future borrowings," and "is in-line with industry standards." Moody's Investor Service[9] commented that our financial policy was "supportive of LIPA's objective of gradually improving its credit quality." All 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."

Taxes Have Grown to Be LIPA's Third Largest Cost

As a not-for-profit utility, LIPA is exempt from federal and state corporate income taxes but makes payments in-lieu-of taxes ("PILOTs") on its transmission and distribution ("T&D") system property[10] and reimburses the property taxes paid by the private owners of power plants under contract to serve our customers. LIPA also pays revenue taxes and assessments. The combined total of these PILOTs, taxes, and assessment was $540 million or 15 percent of LIPA's customer bills in 2015, (see Chart 10). This compares to a national average of 5.5 percent for public power utilities and 4.2 percent for investor-owned utilities[11] — meaning that Long Island electric rates would be 10 percent lower compared to national averages simply by lowering the hidden tax burden on LIPA's customers to the national average. Taxing the electric utility could be viewed as a way to pay for necessary and valuable local government services; however, some taxing jurisdictions have succeeded in transferring far more of their costs to island-wide electric customers than others.

The LIPA Reform Act provided much needed tax relief to LIPA customers in several ways, including eliminating a gross receipts tax, eliminating sales taxes, and incorporating, beginning in 2015, a 2 percent cap on annual increases in LIPA's T&D system property PILOTs[12]. Prior to the 2 percent property PILOT cap, these PILOTs grew at the rate of 7 to 8 percent annually for many years. With the 2 percent PILOT cap and these other changes, LIPA's customers will save more than $200 million over the next three years. Notably, in 2015, the first year of the 2 percent PILOT cap, a number of municipalities billed LIPA in excess of the 2 percent cap, and LIPA defended the cap in court on behalf of our customers.

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8 See Fitch Ratings reports November 2015 and February 2016.

9 See Moody's Investor Service rating report November 2015.

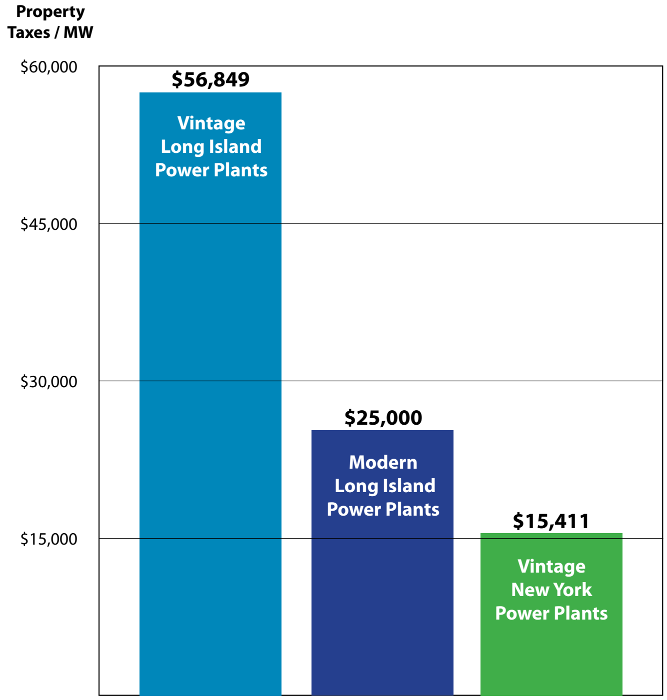
10 LIPA is one of the few publicly owned utilities to pay property tax PILOTs; most public power utilities are exempt from the property tax system while some pay a percentage of revenue to host governments in lieu of property taxes.

11 Source: Payments and Contributions by Public Power Distribution Systems to State and Local Governments, American Public Power Association, March 2014.

12 The 2 percent cap does not apply to privately owned power plants under contract to LIPA.

LIPA is also pursuing property tax relief on four local power plants it has under contract that were formerly owned by LILCO. The over-taxation of these four local power plants can readily be seen in Chart 11. In dollar terms, the current rate of taxation on these vintage plants averages nearly $57,000 per megawatt. By comparison, the property taxes on modern power plants on Long Island are about $25,000 per megawatt and vintage power plants located elsewhere in New York pay approximately $15,000 per megawatt, which is about a quarter of the taxes paid by LIPA's customers, a difference of more than $110 million per year. LIPA has filed tax grievances for these four power plants for every year since 2010. We have sought through negotiation to find an amicable solution for all of our customers, but to date that has proved elusive, and litigation may continue for quite some time.

Chart 11: Property Taxes on Power Plants Per Megawatt of Installed Capacity



Looking Forward to 2016

The completion of PSEG Long Island's Integrated Resource Plan ("IRP") is among our most important goals for 2016. This IRP will provide an updated roadmap for Long Island's energy future, including the transition from aging fossil-fueled power plants to a modern, clean, distributed system of power generation. PSEG Long Island has been soliciting public participation into the IRP planning process, and I encourage interested parties, if you have not done so already, to reach out to PSEG Long Island with your thoughts. PSEG Long Island is expected to present its initial IRP analysis this Spring, followed by a refined analysis in the Fall, and LIPA and DPS will carefully review the alternatives presented.

LIPA is also closely monitoring developments at the state PSC in the REV proceeding. Of particular note, we expect the PSC will address a number of electric rate design issues during 2016 to encourage greater choice and efficiency, and thereby reduce cost for all customers. We look forward to presenting the LIPA Board of Trustees with similar proposals.

I feel extraordinarily privileged to work at LIPA, a not-for-profit utility run for the benefit of our customers. The 42 men and women who work with me at our public authority do outstanding work on behalf of Long Island — often dealing with highly complex issues on which not everyone will agree, and always acting transparently and in the public interest. This letter outlines our progress in executing our plans and addressing some long-standing challenges. We still have much to do, however we are on the right path to meeting the goals articulated by Governor Cuomo and the Legislature in the LIPA Reform Act a little over two years ago.

Thomas Falcone

Thomas Falcone
Chief Executive Officer

March 31, 2016

BOARD OF TRUSTEES

EXECUTIVE STAFF

Thomas Falcone
Chief Executive Officer &
Chief Financial Officer[1]

Jon Mostel
General Counsel and Secretary

Rick Shansky
Managing Director of
Contract Oversight

Bobbi O'Connor
Deputy General Counsel and
Assistant Secretary

Kenneth Kane
Managing Director of Finance

John Little
Managing Director of Planning
and Strategy

Donna Mongiardo
Controller

Kathleen Mitterway
Director of Audit

Barbara Ann Dillon
Director of Human Resources
and Administration

1 Mr. Falcone will continue to serve as Chief Financial Officer until a successor is named.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction

The Long Island Power Authority (the Authority) is a component unit of New York State (State). The Authority became the retail supplier of electric service in the Counties of Nassau and Suffolk (with certain limited exceptions) and a portion of Queens County known as the Rockaways (Service Area), on May 28, 1998 by acquiring the transmission and distribution (T&D) system of the Long Island Lighting Company (LILCO) as a wholly-owned subsidiary of the Authority. As part of the acquisition, the Authority also acquired an undivided 18% interest in the Nine Mile Point Unit 2 (NMP2) generating facility, located in upstate New York, which is operated and managed by Exelon Corporation.

Since the acquisition, LILCO has conducted business under the names LIPA and Power Supply Long Island, referred to collectively as the Authority. The Authority provides electric delivery service in the Service Area, which includes approximately 1.1 million customers. The population of the Service Area is approximately 2.9 million.

In order to assist the Authority in providing electric service to its customers, the Authority entered into operating agreements, the purpose of which was to provide the Authority with the operating personnel and a significant portion of the power supply resources necessary for the Authority to provide electric service in the Service Area. From 1998 through 2013, the service providers were generally National Grid plc, certain National Grid Subsidiaries and their predecessors (collectively, National Grid Subs), with some exceptions. A National Grid Sub was the T&D System manager pursuant to a Management Services Agreement (MSA), which expired at the end of 2013. T&D System management services included, among other functions, the day-to-day operation and maintenance of the T&D System, customer service, billing and collection, meter reading and forecasting.

Effective January 1, 2014, the Authority's role significantly changed as a result of the LIPA Reform Act (Reform Act). The Reform Act was passed and codified as Chapter 173, Laws of New York on June 21, 2013 by the New York State Assembly and Senate. The Reform Act is divided into two parts, Part A and Part B. Part A addresses the reorganization of the Authority and substantially changed its operating responsibilities. Under the Authority's new business model, PSEG Long Island was selected as the Authority's service provider pursuant to the Amended and Restated Operations Services Agreement (A&R OSA). Under the A&R OSA, the PSEG Long Island management company is the contracting entity with the Authority. PSEG Long Island is a wholly owned subsidiary of Public Service Enterprise Group (PSEG). The A&R OSA provides for the operation, maintenance and related services for the T&D system. PSEG Long Island is paid a management fee and may earn incentives related to specified performance metrics. Essentially all costs of operating and maintaining the Authority's T&D system incurred by PSEG Long Island are passed through to and paid for by the Authority.

The Authority also has a fuel management contract with PSEG Energy Resources and Trade LLC (PSEG ER&T) to provide for services related to fuel and power supply management and certain commodity activities. Separately from its fuel management contract with PSEG ER&T, the Authority maintains several power purchase agreements with third party power merchants.

(Amounts in thousands, unless otherwise stated)

Part B of the Reform Act created the Securitization Law which established the Utility Debt Securitization Authority (UDSA). The Securitization Law's sole purpose was 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 basis. The restructuring bonds are to be repaid by an irrevocable, nonbypassable 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.

Overview of the Consolidated Financial Statements

The Authority is engaged in business type activities and follows financial reporting for enterprise funds. The Authority's financial statements are prepared on an accrual basis in accordance with generally accepted accounting principles (GAAP) as prescribed by the Governmental Accounting Standards Board (GASB).

The management's discussion and analysis of the Authority's financial performance provides an overview of the Authority's financial information for the years ended December 31, 2015 and 2014. The discussion and analysis should be read in conjunction with the Basic Financial Statements and the accompanying notes, which follow this section. The notes are an integral part of the Authority's Basic Financial Statements and provide additional information on certain components of these statements.

The Authority's Consolidated Statements of Net Position as of December 31, 2015, 2014 and 2013 are summarized below:

	2015	2014	2013
ASSETS & DEFERRED OUTFLOW OF RESOURCES			
Capital assets	$ 7,548,163	6,727,057	6,683,026
Current assets	1,786,878	1,884,739	1,686,216
Regulatory assets	1,373,147	1,553,135	936,431
Other noncurrent assets	2,072,100	2,867,380	2,423,154
Deferred outflow of resources	254,352	163,341	236,337
Total assets & deferred outflow of resources	**13,034,640**	**13,195,652**	**11,965,164**
LIABILITIES & DEFERRED INFLOW OF RESOURCES			
Long-term debt, net	7,432,468	7,551,891	6,984,635
Current liabilities	1,405,757	1,236,358	1,577,635
Regulatory liabilities	30,027	40,245	-
Other noncurrent liabilities	3,168,580	3,458,049	3,012,687
Deferred inflow of resources	516,309	474,517	12,106
Total liabilities & deferred inflow of resources	12,553,141	12,761,060	11,587,063
Total net position	481,499	434,592	378,101
Total liabilities, deferred inflows of resources & net position	**$ 13,034,640**	**13,195,652**	**11,965,164**

2015 Compared to 2014

The primary change in the Authority's combined financial condition as of December 31, 2015 and 2014 were as follows:

Assets and deferred outflows of resources

Assets and deferred outflows or resources decreased $161 million compared to 2014 due to decreases of $795 million in noncurrent assets, $180 million in regulatory assets, and $98 million in current assets, partially offset by increases of $821 million in capital assets and $91 million in deferred outflow of resources.

Capital assets increased $821 million compared to 2014 primarily due to the reclassification of the accumulated depreciation reserve imbalance as calculated by a new depreciation study totaling $718 million. The Authority's Three Year Rate Plan for 2016, 2017 and 2018, as approved by the Authority's Board in December 2015, authorized reducing the unamortized balance of the Acquisition Adjustment by this same amount. The remaining increase was due to construction projects totaling $386 million partially offset by asset retirements and annual depreciation expense.

Current assets decreased by $98 million compared to 2014 primarily due to a lower receivable as the Authority received payment of $80 million for a Community Development Block Grant. This was partially offset by increased commodity derivative collateral posted by the Authority as of December 31, 2015.

Regulatory assets decreased by $180 million primarily due to a $130 million decrease in retirement benefit obligations related to the workforce of the Authority's service provider, reflecting an updated actuarial valuation plus the annual amortization of prior service costs. Also contributing to the decrease was the elimination of deferred transition costs totaling $46 million, as approved by the Authority's Board in December 2015, and the collection of the Shoreham property tax settlement receivables of $12 million. The remaining decrease was due to the normal annual collection of certain long term regulatory assets. Partially offsetting these decreases was the recognition of a regulatory asset related to the revenue decoupling mechanism, totaling $17 million. For a full discussion of the Authority's regulatory assets and liabilities, see notes 3 and 4 to the Authority's Basic Financial Statements.

Noncurrent assets decreased by $795 million primarily due to the reclassification of the accumulated depreciation reserve imbalance from capital assets to an offset to the unamortized balance of the Acquisition Adjustment, as discussed above. The remaining decrease was due to the change in the deferred mark to market on certain of the Authority's financial derivatives.

Deferred outflow of resources increased by $91 million primarily due to the deferred loss incurred on the refunding of a portion of the Authority's debt with the issuance of the 2015 UDSA Restructuring Bonds. The deferred loss represents the difference between the reacquisition price and the carrying amount of the refinanced debt. Although the refinancing recognized a deferred loss on refunding as provided for under the accrual method of accounting, the refunding produces net present value savings of $128 million over the life of the UDSA Restructuring Bonds due to lower interest costs.

Liabilities and deferred inflows of resources

Liabilities and deferred inflows of resources decreased $208 million due to decreases of $119 million in long-term debt-net, $10 million in regulatory liabilities, and $289 million in noncurrent liabilities, partially offset by increases of $169 million in current liabilities and $42 million in deferred inflow of resources.

Net long-term debt decreased $119 million primarily due to scheduled maturities of $180 million offset by the accretion of the capital appreciation bonds, amortization of bond discounts and premiums, and the issuance of long-term debt. The Authority issued $200 million Electric System General Revenue Bonds Series 2015A to refinance outstanding variable rate demand bonds with expiring bank facilities. The Authority issued $117 million Electric System General Revenue Bonds Series 2015B, which generated premiums of approximately $13 million, to fund construction projects. The Authority issued $149 million Electric System General Revenue Bonds Series 2015C to refinance outstanding variable rate bonds with expiring bank facilities.

In addition, the UDSA issued $1.022 billion of Restructuring Bonds, Series 2015, which generated premiums of approximately $177 million, and allowed the Authority to retire approximately $1.045 billion of its existing debt with the proceeds from the UDSA transaction.

Regulatory liabilities decreased $10 million due to the return to customers of 2014 excess collections of fuel and purchased power costs totaling $40 million offset by the recognition of 2015 excess collections of $30 million. In accordance with the Authority's tariff any over/under collection of fuel and purchased power costs are returned/collected in the subsequent month.

Noncurrent liabilities decreased $289 million primarily due to the $191 million related to the current portion of the Authority's capital lease obligations and an $87 million decrease in retirement benefit obligations related to the workforce of the Authority's service provider resulting from an updated actuarial valuation plus the cash funding of pension obligations made by the Authority in 2015.

Deferred inflows of resources increased $42 million due to additional advanced funds received from the Federal Emergency Management Agency (FEMA) totaling $61 million partially offset by the change in market to market value of certain of the Authority's derivatives instruments.

2014 Compared to 2013

The primary change in the Authority's combined financial condition as of December 31, 2014 and 2013 were as follows:

Assets and deferred outflows of resources

Assets and deferred outflows of resources increased $1.23 billion compared to 2013 due to increases of $44 million in capital assets, $199 million in current assets, $444 million in noncurrent assets and $617 million in regulatory assets partially offset by the decrease of $73 million in deferred outflows of resources.

Capital assets increased $44 million due to net construction work in process increases of $443 million. Offsetting this increase were asset retirements, reductions caused by accumulated depreciation and reclasses to regulatory assets for certain projects not owned by the Authority but generated for the sole benefit of the Authority.

Current assets increased $199 million compared to 2013 primarily due to an increase in cash and cash equivalents resulting from bond proceeds. Bond proceeds of $511 million funded past and future capital expenditures while $150 million was to refinance variable rate notes callable on January 2, 2015, and therefore held as available cash at year-end.

Regulatory assets increased $617 million compared to 2013 primarily due to an increase of the costs associated with A&R OSA employee retirement benefits totaling $598 million; PSEG Long Island implementing new enterprise resource planning and outage management systems totaling $42 million and $27 million, respectively; and power supply management transition costs totaling $19 million. These increases were partially offset by a decrease of $13 million related to the Shoreham Property Tax Settlement Agreement (discussed in note 4 to the Basic Financial Statements); $46 million of 2013 deferred under recovery of fuel and purchased power costs that were fully recovered during 2014; and the amortization of various deferred costs totaling $10 million.

Noncurrent assets increased $444 million compared to 2013 primarily due to an increase in restricted cash and cash equivalents. During 2014, the Authority received $774 million in grant proceeds from FEMA. The grant proceeds included $301 million from FEMA related to reimbursements for Superstorm Sandy, $441 million related to advance funding from FEMA of an ongoing storm hardening program and $32 million from other grants. The balance of the FEMA funds are held as noncurrent restricted as they are held for storm hardening capital projects to strengthen the Long Island Electric grid to the effects of severe weather.

Deferred outflow of resources decreased $73 million due to the $30 million annual amortization of the deferred loss incurred on the refunding of a portion of the Authority’s debt with the issuance of the 2013 UDSA Restructuring Bonds. Also contributing to the decrease was the $43 million change in the market to market value of the Authority’s hedging commodity derivatives.

Liabilities and deferred inflows of resources

Liabilities and deferred inflows of resources increased $1.17 billion due to increases of $567 million in long-term debt-net, $445 million in noncurrent liabilities, $40 million in regulatory liabilities, and $462 million in deferred inflows of resources. These increases were partially offset by a decrease of $341 million in current liabilities.

Net long-term debt increased due to the issuance of $615 million of Electric System General Revenue Bonds, including an issuance premium of $37 million. The Authority also issued $150 million of floating rate notes to refinance $150 million of its variable rate bonds; however, the existing variable rate bonds were not callable until January 2, 2015, and therefore were outstanding at year-end. Offsetting this was a decrease in unamortized discounts and premiums and scheduled maturities of outstanding debt instruments.

Current liabilities decreased $341 million primarily due to reimbursements made to the Authority’s prior service provider during 2014 for Superstorm Sandy costs.

(Amounts in thousands, unless otherwise stated)

Regulatory liabilities increased $40 million resulting from the deferral of the over collection of fuel and purchased power costs. The Authority's power supply charge is reset monthly based on actual and forecast costs. The over collection reduced the power supply charge in 2015.

Other noncurrent liabilities increased $445 million primarily due to the costs associated with A&R OSA employee retirement benefits totaling $578 million partially offset by the annual amortization of the Authority's capital lease obligations.

Deferred inflows of resources increased $462 million due to a grant received from the FEMA totaling $448 million. The remaining increase is due to the change in mark to market value of certain of the Authority's derivatives instruments.

Results of Operations

The Authority's Consolidated Statements of Revenues, Expenses and Changes in Net position for the years ended December 31, 2015, 2014 and 2013 are summarized as follows:

		2015	2014	2013
Electric revenue	$	3,505,209	3,613,982	3,755,832
Operating expenses		(3,187,383)	(3,351,379)	(3,434,973)
Interest expense		(361,725)	(358,490)	(334,881)
Total expenses		(3,549,108)	(3,709,869)	(3,769,854)
Revenue less operating and interest expenses		(43,899)	(95,887)	(14,022)
Grant income		54,329	114,521	27,315
Other income		37,744	37,857	34,134
Total other income		92,073	152,378	61,449
Change in net position	$	48,174	56,491	47,427
Beginning net position		434,592	378,101	330,674
Cumulative effect of change in accounting principle		(1,267)	-	-
Net position, beginning of year, as restated		433,325	378,101	330,674
Net position, end of year	$	481,499	434,592	378,101

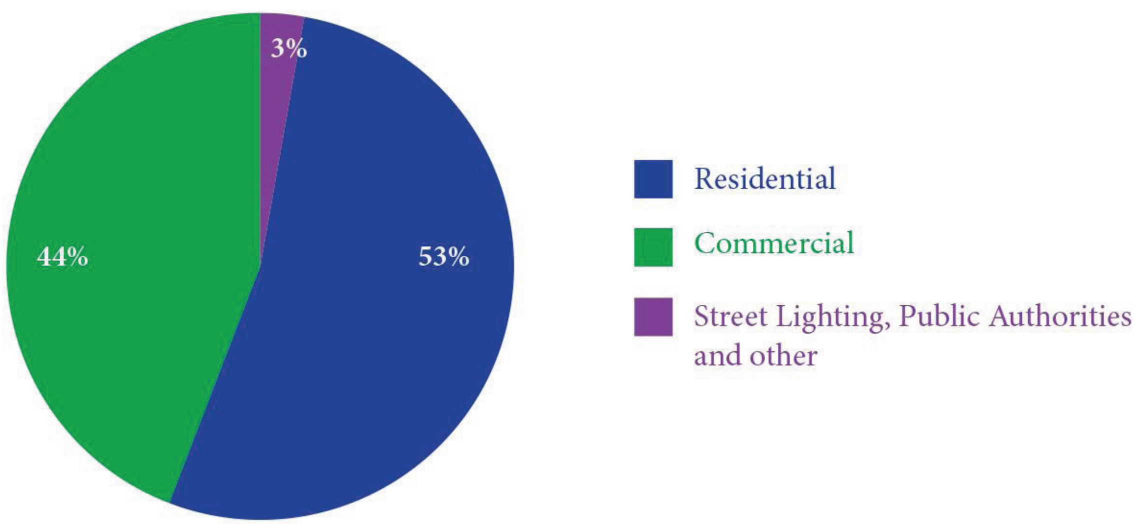
2015 Compared to 2014

Operating revenues

Electric revenue for 2015 totaled $3.50 billion, a decrease of $109 million compared to 2014 due to lower fuel and purchased power costs, which were passed through to customers in lower electric rates, partially offset by higher delivery revenues due to higher sales during the winter of 2015. For the year ended December 31, 2015, approximately 53% of LIPA's annual retail revenues were received from residential customers, 44% from commercial customers and 3% from street lighting, public authorities and certain others. The largest customer in the service area (the Long Island Rail Road) accounted for less than two percent of total sales and less than two percent of revenue. In addition, the ten largest customers in the service area accounted for approximately seven percent of total sales and less than seven percent of revenue.

(Amounts in thousands, unless otherwise stated)

Revenue from Sales of Electricity by Customer Class



	2015	2014	2013
Revenues from Sales of Electricity*			
Residential	$ 1,860,865	$ 1,883,319	$ 1,966,898
Commercial	1,537,844	1,618,297	1,681,406
Street Lighting, Public Authorities and Other	106,500	112,366	107,528
Totals	**$ 3,505,209**	**$ 3,613,982**	**$ 3,755,832**

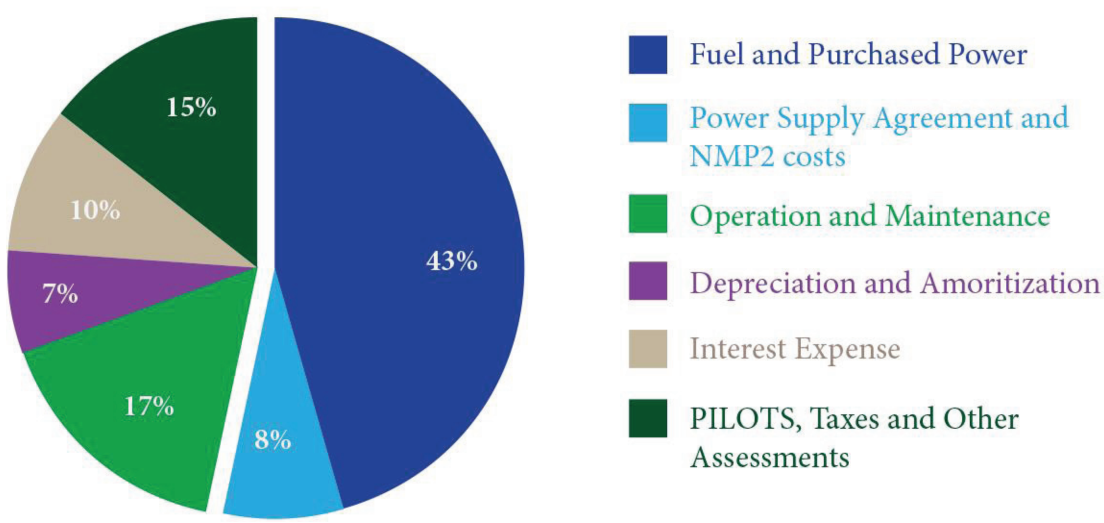
** Amounts related to deferral mechanisms have been allocated to each class as shown.*

Operating and interest expenses

Operating expenses for 2015 totaled $3.19 billion a decrease of $164 million compared to 2014 primarily due to lower fuel and purchased power costs of $149 million. The remaining decrease was primarily due to lower costs incurred for finance and information technology expenses after the transition to the Authority's new service provider for these services in 2015. Interest expenses for 2015 totaled $362 million, an increase of $3 million compared to 2014 primarily due to higher debt balances outstanding during 2015.

The Authority's operating and interest expenses are comprised of costs associated with operating and maintaining the Authority's T&D system and financing the capital projects related to maintaining the reliability of electric service. For the year ended December 31, 2015, approximately 51% of the Authority's expenses were associated with providing generated and purchased power, including fuel and purchased power expenses of 43%, the Amended and Restated Power Supply Agreement (A&R PSA) with National Grid of 7%, and the Authority's share of operating costs associated with the NMP2 nuclear generating station of 1%. Operations and maintenance expenses associated with the T&D system comprised 17% of expenses in 2015. Payments made in lieu of taxes (PILOTs), taxes paid pursuant to contract on the A&R PSA generating units, and other taxes and assessments were 15% of expenses. Interest expenses were 10% of expenses in 2015 while depreciation and amortization was 7%.

2015 Operating and Interest Expenses



Other income

Grant income decreased $60 million compared to 2014 primarily due to an $80 million Community Development Block grant recognized in 2014 to pay for the costs not reimbursed by FEMA related to Superstorm Sandy and other FEMA declared weather events.

Net position, Cumulative effect of change in accounting principle

During 2015, the Authority adopted GASB No. 68, *Financial Reporting for Pension Plans-an amendment of GASB No. 27.* GASB No. 68 changed how the Authority calculates and reports the costs and obligations associated with pensions. For the Authority, this Statement became effective January 1, 2015. This resulted in a reduction to the Authority's net position of $1.3 million for the opening balance of the Authority's allocated share of the net pension liability. For a full discussion of the Authority's net pension liability, see note 13 to the Basic Financial Statements.

2014 Compared to 2013

Operating revenues

Revenue for 2014 decreased $142 million compared to 2013 primarily due to lower sales as a result of the mild summer weather experienced in 2014. Also contributing to the decrease were lower fuel and power supply charges totaling $91 million, which were passed through to customers in lower electric rates, including $56 million due to lower commodity costs and $35 million due to lower sales.

Operating and interest expenses

Total operating expenses for 2014 decreased $84 million compared to 2013. Fuel and purchased power expenses decreased $91 million due to lower sales and lower commodity costs. Also contributing to the decrease was $64 million lower depreciation expense resulting from the implementation of a new depreciation study during 2014. Offsetting these decreases were higher operations and maintenance costs related to the operating structure with the Authority's new service provider, which became effective on January 1, 2014.

Interest charges increased $24 million compared to 2013 primarily due to noncash charges associated with the deferred loss amortizations on the 2013 UDSA refinancing transaction. The deferred loss represents the difference between the reacquisition price and the carrying amount of the refinanced debt. The refinancing provided net present value savings of $132 million over the life of the UDSA Restructuring Bonds due to lower interest costs.

Other income

Grant income increased $87 million compared to 2013 million primarily due to an $80 million Community Development Block grant to pay for the costs not reimbursed by FEMA related to Superstorm Sandy and other declared weather events, plus a $10 million increase in the grant received from the New York State Energy Research and Development Authority (NYSERDA) to offset a portion of the costs of the Authority's energy efficiency and renewable programs.

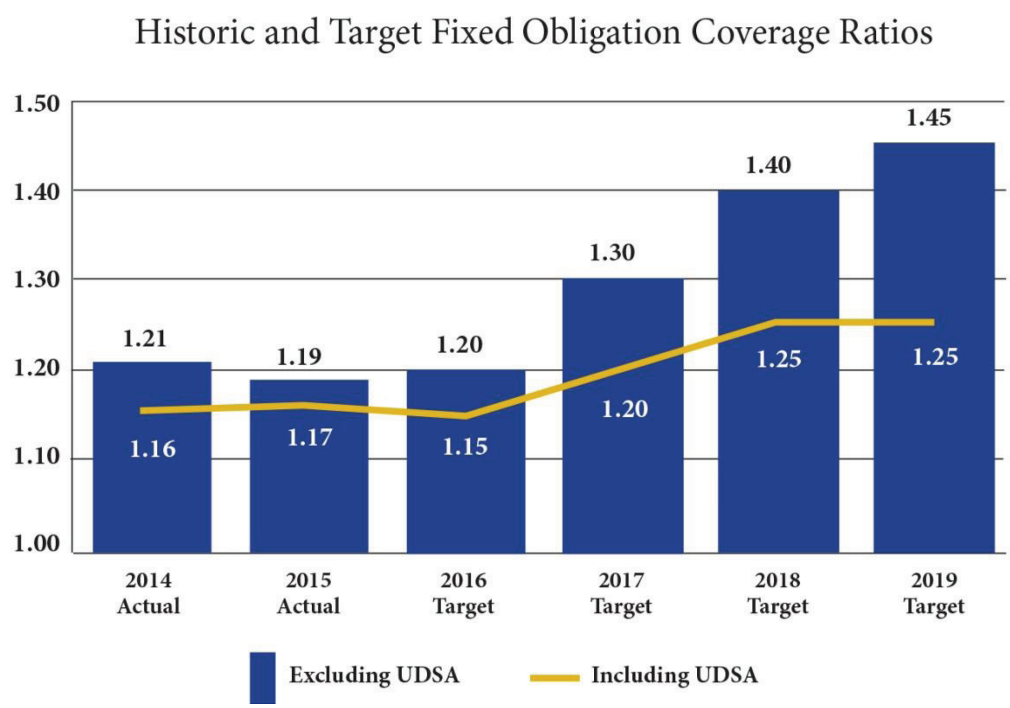
Other income increased $4 million compared 2013 primarily due to gains realized on the Authority's NMP2 trust account.

Fixed Obligation Coverage Ratios

The Authority's fixed obligation coverage ratios for the years ended December 31, 2015 and 2014 were 1.19x and 1.21x, respectively. Inclusive of UDSA restructuring bonds, the fixed obligation coverage ratios were 1.17x and 1.16x.

In December 2015, the Authority's Board approved a Three Year Rate Plan, as recommended by the New York Department of Public Service. The Three Year Rate Plan incorporated a new Board-adopted financial policy that seeks to reduce the portion of the Authority's capital plan funded by debt to 64% or less and raise the Authority's credit ratings to A2 by Moody's Rating Service, A by Standard and Poor's, and A by Fitch Ratings over five years. To achieve these goals, the Rate Plan adopted the "public power model" of budgeting and rate setting proposed by PSEG Long Island and Authority staff, which makes use of the debt service coverage method of determining revenue requirements. For the Authority, this entails transitioning from the historic use of a $75 million budget for net income to budgeting to achieve fixed obligation coverage targets (including capitalized leases) on Authority issued debt of a minimum 1.20x, 1.30x, and 1.40x in 2016, 2017, and 2018 (and 1.45x in 2019 after the Three Year Rate Plan). When the UDSA restructuring bonds are included, these coverage ratio targets are a minimum of 1.15x, 1.20x, and 1.25x in 2016, 2017, and 2018. The Authority's methodology for calculating fixed obligation coverage ratios excludes certain specified non-cash items from expenses. The Authority cannot predict whether any of the targets or goals of the Three Year Plan will be realized.

For a full discussion for the fixed obligation coverage ratio calculation, see notes 3 and 11 to the Basic Financial Statements. The Authority's historic and projected fixed obligation coverage ratios are shown below.



(Amounts in thousands, unless otherwise stated)

Financing Activities

The Authority's consolidated debt at December 31, 2015, 2014 and 2013, including current maturities, is comprised of the following instruments:

		2015	2014	2013
Long-term debt:				
General Revenue Bonds	$	4,380,595	5,246,726	4,594,248
Subordinated Revenue Bonds		—	350,000	350,000
UDSA Restructuring Bonds		2,919,439	1,932,324	2,022,324
Total long-term debt	$	7,300,034	7,529,050	6,966,572
Short-term debt:				
General Revenue Notes		—	65,000	263,000
General Revenue Commercial Paper Notes		50,000	—	—
Subordinated Commercial Paper Notes		300,000	215,000	
Total short-term debt	$	350,000	280,000	263,000
Total debt	$	7,650,034	7,809,050	7,229,572

Financing Transactions for Years 2015 and 2014

The table below summarizes the financing activity for the Authority and the UDSA for the years ended December 31, 2015 and 2014:

		Bonds to Fund Capital Projects	Refinancing of Fixed-Rate Bonds for Savings	Refinancing of Variable-Rate Bonds
2015:				
General Revenue Bonds	$	117,230	-	349,000
UDSA General Revenue Bonds		-	1,002,115	-
2014:				
General Revenue Bonds	$	555,750	22,270	150,000

The Authority issued new long-term debt to fund capital improvements in 2015 and 2014. The Authority also refinanced certain long-term variable-rate bonds that had bank facilities subject to periodic renewal in 2015 and 2014. Additionally, in 2014, the Authority issued $22.3 million of bonds to refinance existing fixed-rate debt for interest savings.

(Amounts in thousands, unless otherwise stated)

On March 30, 2015, the Securitization Law was amended allowing for a total issuance of up to $4.5 billion of UDSA restructuring bonds, inclusive of the $2.0 billion of restructuring bonds issued pursuant to Financing Order No. 1 in December 2013. On October 16, 2015, the UDSA through Financing Order No.2, issued $1.0 billion Series 2015 Restructuring Bonds, thereby creating $128 million of net present value savings.

For a full discussion on the Authority's debt activities during 2015 and 2014, see note 11 to the Basic Financial Statements.

Liquidity and Capital Resources

The Authority's Board adopted a policy in December 2015 that the Authority should at all times maintain cash on hand and available credit equivalent to at least 120 days of operating expenses. The Authority's available sources of liquidity for operating purposes and capital program funding at December 31, 2015 and 2014, included the following resources:

		2015	2014
Operating liquidity			
Unrestricted cash and cash equivalents	$	578,619	760,161
OPEB account cash, cash equivalents & investments		51,579	22,305
Restricted cash - Working capital requirements		208,099	148,280
Total operating liquidity		838,297	930,746
Available Credit			
General Revenue Notes - Revolving Credit Facility		337,500	435,000
General Revenue Commercial Paper		275,000	-
Subordinated Revenue Commercial Paper		-	385,000
Total available credit		612,500	820,000
Total cash, cash equivalents, investments & available credit	$	1,450,797	1,750,746
Restricted cash			
FEMA - restricted		501,990	447,621
UDSA		33,518	22,483
Total restricted cash	$	535,508	470,104

The Authority's unrestricted cash, cash equivalents and investments totaled $630 million and $782 million, inclusive of the Other Postemployment Benefits (OPEB) Account balances, at December 31, 2015 and 2014, respectively.

The Authority also had approximately $208 million and $148 million at December 31, 2015 and 2014, respectively, of restricted cash and cash equivalents dedicated to prefunding PSEG Long Island's working capital needs. These accounts are owned by the Authority and are available solely for the Authority's costs. The funds are restricted due to the contractual obligation to pre-fund the accounts from which PSEG Long Island, acting as agent for the Authority, pays expenses related to operating the Authority's electric system. The Authority considers these to funds to be part of its working capital to meet operating and capital expenditures.

In December 2014, the Authority established an OPEB Account to prefund certain future cash out-lays of post-employment health and life insurance expenses. The Authority had on deposit in the OPEB Account $52 million and $22 million as of December 31, 2015 and 2014, respectively. The OPEB Account is primarily invested in assets typically associated with these long-life liabilities; however, the funds are available in the event that revenues are insufficient to pay reasonable and necessary operating expenses or to make payments on bonds or parity obligations, and therefore are part of unrestricted cash and investments.

Included in restricted cash and equivalents as of December 31, 2015 and 2014 was $502 million and $448 million, respectively of advance funding provided by FEMA for storm restoration and storm hardening capital projects. The storm hardening projects are intended to strengthen the Long Island electrical grid to the effects of severe weather, and the Authority expects the storm hardening program to continue through 2018. The Authority expects this storm mitigation program to continue through 2018. The Authority also had restricted cash and equivalents related to UDSA debt service payments and required debt service and operating reserves of $34 million and $22 million as of December 31, 2015 and 2014, respectively.

In 2014, the Authority's Board authorized short-term borrowing programs of up to $1 billion. These short-term borrowing programs provide the resources to meet interim working capital needs, fund the Authority's capital program between long-term debt offerings, and meet any cash flow requirements from severe weather events. Among other factors, the Authority's operating and capital needs vary during the year given the summer peaking seasonal nature of its sales.

In 2015, the Authority established a $325 million Senior Lien Series 2015 General Revenue Notes program (GR Notes), of which $50 million was outstanding at December 31, 2015. In December 2014, the Authority established a $300 million Series 2014 Commercial Paper Program (CP Program), none of which was outstanding at December 31, 2015. The Series 2014 CP Program replaced a prior $300 million commercial paper program that expired in January 2015. The prior CP Program had $215 million outstanding at December 31, 2014. During 2013, the Authority established a $500 million Revolving Credit Agreement (Revolver) with a syndicate of banks, of which $0 and $65 million was outstanding as of December 31, 2015, and 2014, respectively. During 2015, the Authority extended the term by one year and reduced the authorized size of the Revolver from $500 million to $337.5 million.

The short-term borrowing programs are supported by various bank agreements that expire during 2017, 2018, and 2020, and management expects to renew or replace the agreements as needed prior to their expiration.

The Authority believes it will have sufficient liquidity throughout 2016 to meet its planned operating, maintenance, and capital programs.

Risk Management

The Authority is exposed to commodity and interest rate risk during the conduct of its operations. To mitigate commodity risk, the Authority established a power supply risk management program designed to mitigate a portion of the exposure to fluctuations in commodity prices on behalf of its customers. The Authority also hedges its interest rate exposure through certain interest rate derivatives based on established interest rate swap guidelines.

In accordance with GASB No. 53, *Accounting and Financial Reporting for Derivative Instruments*, the Authority records its hedging and investment derivatives at fair value and records deferred inflows and outflows for changes in fair values on hedging derivatives. The Authority defers, as unrealized gains and losses, changes in fair value for investing derivatives consistent with its rate-making practices.

For a further discussion on these matters, see note 7 to the Basic Financial Statements.

Bond Ratings

Below are the long-term ratings of the Authority's and the UDSA's securities as rated by Moody's Investors Service (Moody's), Standard and Poor's Ratings Services (S&P), and Fitch Ratings (Fitch):

	Investment ratings		
	Moody's	**S&P**	**Fitch**
Senior Lien Bonds	Baa1	A-	A-
Subordinate Lien Bonds	Baa2	--	A-
UDSA Restructuring Bonds	Aaa (sf)	AAA (sf)	AAA (sf)

Certain bonds and notes of the Authority are supported by either a bank letter of credit or are insured against default. Such debt carries the higher of the ratings of the credit support provider or that of the Authority.

Contacting the Long Island Power Authority

This financial report is designed to provide the Authority's bondholders, customers, and other interested parties with a general overview of the Authority's finances and to demonstrate its accountability for the funds it receives. If you have any questions about this report or need additional information, contact the Authority at 333 Earle Ovington Blvd., Suite 403, Uniondale, New York 11553, or visit the Authority's website at www.lipower.org.

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Board of Trustees
Long Island Power Authority:

Report on the Financial Statements

We have audited the accompanying basic financial statements of the Long Island Power Authority (the Authority), a component unit of the state of New York, which comprise the statements of net position as of December 31, 2015 and 2014, and the related statements of revenues, expenses, and changes in net position, and cash flows for the years then ended, and the related notes to the basic financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these basic financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these basic financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the basic financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the basic financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the basic financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the basic financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion on the Financial Statements

In our opinion, the basic financial statements referred to above present fairly, in all material respects, the financial position of the Authority as of December 31, 2015 and 2014, and its changes in net position, and cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Other Matters

Required Supplementary Information

U.S. generally accepted accounting principles require that the information in the Management's Discussion and Analysis and Required Supplementary Information be presented to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audits of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Supplementary and Other Information

Our audits were conducted for the purpose of forming an opinion on the basic financial statements as a whole. The Consolidating Statements of Revenues, Expenses, and Changes in Net Position is presented for purposes of additional analysis and is not a required part of the basic financial statements.

The Consolidating Statements of Revenues, Expenses, and Changes in Net Position is the responsibility of management and was derived from and relates directly to the underlying accounting and other records used to prepare the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and certain additional procedures, including comparing and reconciling such information directly to the underlying accounting and other records used to prepare the basic financial statements or to the basic financial statements themselves, and other additional procedures in accordance with auditing standards generally accepted in the United States of America. In our opinion, the Consolidating Statements of Revenues, Expenses, and Changes in Net Position is fairly stated in all material respects in relation to the basic financial statements as a whole.

The Schedule of the Authority's Proportionate Share of the Net Pension Liability has not been subjected to the auditing procedures applied in the audits of the basic financial statements, and accordingly, we do not express an opinion or provide any assurance on it.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated March 21, 2016 on our consideration of the Authority's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the Authority's internal control over financial reporting and compliance.

KPMG LLP

New York, NY
March 21, 2016

LONG ISLAND POWER AUTHORITY
(A Component Unit of the State of New York)

Statements of Net Position

December 31, 2015 and 2014

(Amounts in thousands)

Assets and Deferred Outflows of Resources		**2015**	**2014**
Current assets:			
Cash and cash equivalents	$	600,698	782,466
Restricted cash – working capital requirements		208,099	148,280
Restricted cash		33,518	22,483
Investments		29,500	—
Counterparty collateral – posted by the Authority		48,357	4,500
Accounts receivable (less allowance for doubtful accounts of $38,036 and $38,817 at December 31, 2015 and 2014, respectively)		489,757	528,937
Other receivables		85,988	145,796
Fuel inventory		117,616	128,201
Material and supplies inventory		47,808	41,538
Unrealized charges		75,574	56,735
Regulatory assets due within one year:			
Operations Services Agreement – employee retirement benefits		54,199	—
Shoreham property tax settlement		43,498	42,462
Employee benefit plan settlement		21,634	—
Revenue decoupling mechanism		17,297	—
New York State assessment		1,708	4,672
Transition costs – Operations Services Agreement		—	4,596
Debt issuance costs		4,100	4,000
Enterprise resource planning system		4,860	3,870
Fuel and purchased power costs		3,108	2,988
Outage management system		2,424	2,430
Transition costs – power supply management		1,692	1,690
Southampton visual benefit assessment		888	948
Prepayments and other current assets		49,963	25,803
		1,942,286	1,952,395
Noncurrent assets:			
Restricted cash and cash equivalents		501,990	447,621
Utility plant and property and equipment, net		7,548,163	6,727,057
Nuclear decommissioning trust		110,436	110,669
Other long-term receivables		38,082	28,325
Unrealized charges		197,227	224,365
Prepayments		12,231	14,533
Regulatory assets:			
Operations services agreement – employee retirement benefits		413,978	597,592
Shoreham property tax settlement		447,414	460,419
Employee benefit plan settlement		194,705	216,339
Transition costs – operations services agreement		—	45,974
Debt issuance costs		38,498	39,140
Enterprise resource planning system		43,670	38,710
Fuel and purchased power costs		34,086	37,311
Outage management system		21,757	24,297
Transition costs – power supply management		15,224	16,918
Southampton visual benefit assessment		8,407	8,779
Acquisition adjustment (net of accumulated amortization)		1,212,134	2,041,867
Total noncurrent assets		10,838,002	11,079,916
Deferred outflows:			
Deferred loss on debt refunding		254,157	159,162
Accumulated decrease in fair value of financial derivatives		—	4,179
Pensions		195	—
Total deferred outflows		254,352	163,341
Total assets and deferred outflows	$	13,034,640	13,195,652

See accompanying notes to basic financial statements.

LONG ISLAND POWER AUTHORITY
(A Component Unit of the State of New York)

Statements of Net Position

December 31, 2015 and 2014

(Amounts in thousands)

Liabilities and Net Position		**2015**	**2014**
Current liabilities:			
Short-term debt	$	350,000	280,000
Current maturities of long-term debt		178,295	164,505
Current maturities of UDSA debt		60,000	15,000
Current portion of capital lease obligation		190,955	178,997
Accounts payable and accrued expenses		456,649	422,222
Counterparty collateral – held by the authority		—	1,150
Regulatory liability – fuel and purchased power costs refundable		30,027	40,245
Commodity derivative instruments		73,599	45,097
Accrued payments in lieu of taxes		10,008	45,678
Accrued interest		47,832	44,443
Customer deposits		38,419	39,266
Total current liabilities		1,435,784	1,276,603
Noncurrent liabilities:			
Long-term debt		4,305,146	5,532,551
Long-term UDSA debt		3,127,322	2,019,340
Capital lease obligations		2,188,295	2,379,250
Borrowings		87,064	91,779
A&R Operations Services Agreement-employee retirement benefit		491,678	578,437
Financial derivative instruments		173,199	192,881
Commodity derivative instruments		44,086	31,062
Asset retirement obligation		62,906	66,414
Long-term liabilities and unrealized credits		93,530	97,291
Claims and damages		27,822	20,935
Total noncurrent liabilities		10,601,048	11,009,940
Deferred inflows:			
Regulatory credits – grants		502,213	441,088
Accumulated increase in fair value of financial derivatives		1,257	—
Accumulated increase in fair value of commodity derivatives		3,257	19,296
Pensions		417	—
Accumulated increase in fair value of Nine Mile Point 2 trust		9,165	14,133
Total deferred inflows		516,309	474,517
Net position:			
Net investment in capital assets		(158,313)	(361,245)
Restricted		142,026	90,615
Unrestricted		497,786	705,222
Total net position		481,499	434,592
Total liabilities, deferred inflows and net position	$	13,034,640	13,195,652

See accompanying notes to basic financial statements.

LONG ISLAND POWER AUTHORITY
(A Component Unit of the State of New York)

Statements of Revenues, Expenses, and Changes in Net Position

Years ended December 31, 2015 and 2014

(Amounts in thousands)

		2015	2014
Operating revenues – electric sales	$	3,505,209	3,613,982
Operating expenses:			
Operations – fuel and purchased power		1,510,725	1,659,272
Operations and maintenance		814,177	851,101
Operations and maintenance – amortizations		11,403	11,422
Storm restoration		63,210	30,462
General and administrative		22,092	29,064
Depreciation and amortization		223,607	215,544
Pass through taxes under certain long-term operating agreements		192,729	184,356
Payments in lieu of taxes and assessments		349,440	370,158
Total operating expenses		3,187,383	3,351,379
Operating income		317,826	262,603
Nonoperating revenues and expenses:			
Other income, net:			
Investment income		5,878	6,989
Grant income – FEMA		13,472	1,707
Grant income – other		40,857	112,814
Carrying charges on regulatory assets		27,594	28,565
Other		4,272	2,303
Total other income, net		92,073	152,378
Interest charges and (credits):			
Interest on long-term debt, net		355,125	338,976
Other interest		13,713	28,475
Allowance for borrowed funds used during construction		(7,113)	(8,961)
Total interest charges and (credits)		361,725	358,490
Change in net position		48,174	56,491
Net position, beginning of year		434,592	378,101
Cumulative effect of change in accounting principle (see note 2)		(1,267)	—
Net position, beginning of year, as restated		433,325	378,101
Net position, end of year	$	481,499	434,592

See accompanying notes to basic financial statements.

LONG ISLAND POWER AUTHORITY

(A Component Unit of the State of New York)

Statements of Cash Flows

Years ended December 31, 2015 and 2014

(Amounts in thousands)

		2015	2014
Cash flows from operating activities:			
Operating revenues received	$	3,667,377	3,740,144
Paid to suppliers and employees:			
Operations and maintenance		(846,041)	(1,156,135)
Pass through taxes under certain long-term operating agreements		(192,729)	(184,356)
Fuel and purchased power		(1,477,789)	(1,624,682)
Payments in lieu of taxes		(437,063)	(461,989)
Collateral on commodity derivative transactions, net		(45,007)	(22,894)
Pension funding		(30,000)	(66,900)
Net cash provided by operating activities		638,748	223,188
Cash flows from investing activities:			
Earnings received on investments		1,143	406
Restricted cash		(125,223)	(344,869)
Purchase of investment securities		(29,500)	—
Other		2,426	2,559
Net cash used in investing activities		(151,154)	(341,904)
Cash flows from noncapital financing related activities:			
Grant proceeds		186,952	777,565
Proceeds from credit facility draws and commercial paper program		500,000	637,000
Redemption of credit facility draws and commercial paper program		(430,000)	(620,000)
Net cash provided by noncapital related activities		256,952	794,565
Cash flows from capital and related financing activities:			
Capital expenditures		(396,286)	(441,007)
Outage management system and enterprise resource planning system		—	(70,318)
Proceeds from insurance recoveries and settlements		—	3,064
Proceeds from the issuance of long-term debt		1,659,264	765,310
Debt issuance costs		(8,658)	(3,724)
Interest paid, net		(344,464)	(333,239)
Redemption of long-term debt		(1,836,170)	(192,290)
Net cash used in capital and related financing activities		(926,314)	(272,204)
Net (decrease) increase in cash and cash equivalents		(181,768)	403,645
Cash and cash equivalents at beginning of year		782,466	378,821
Cash and cash equivalents at end of year	$	600,698	782,466
Reconciliation to net cash provided by operating activities:			
Operating income	$	317,826	262,603
Adjustments to reconcile operating income to net cash provided by operating activities:			
Depreciation and amortization		235,010	215,544
Nuclear fuel burned		14,119	12,365
Shoreham surcharges		38,990	40,507
Accretion of asset retirement obligation		3,802	4,230
Other, net		37,492	5,424
Changes in operating assets and liabilities:			
Accounts receivable, net		3,011	(3,170)
Regulatory assets and liabilities		98,184	115,124
Fuel and material and supplies inventory		4,316	(41,378)
Accounts payable, accrued expenses and other		(114,002)	(388,061)
Net cash provided by operating activities	$	638,748	223,188

See accompanying notes to basic financial statements.

(1) Nature of Operations

The Long Island Power Authority (the Authority) is the owner of the transmission and distribution (T&D) system located in the Counties of Nassau and Suffolk (with certain limited exceptions) and a portion of Queens County known as the Rockaways (Service Area), and is responsible for supplying electricity to customers within the Service Area. The Authority was established as a corporate municipal instrumentality of the State of New York (State), constituting a political subdivision of the State, created by Chapter 517 of the Laws of 1986 (the LIPA Act). As such, it is a component unit of the State and is included in the State's annual financial statements.

The Authority is subject to the LIPA Act and the LIPA Reform Act (Reform Act). Part A of the Reform Act addressed the reorganization of the Authority and changed its operating responsibilities, and Part B, referred to as the Securitization Law, created the Utility Debt Securitization Authority (UDSA). The Securitization Law provided a legislative foundation for the UDSA to issue 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 basis. The restructuring bonds are to be repaid by an irrevocable, nonbypassable 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.

The Reform Act also made certain areas of the operations and rate setting of the Authority and PSEG Long Island subject to the recommendations of the New York Department of Public Service (DPS).

For a further discussion on the UDSA and the DPS, see note 3.

The Authority has operating agreements with service providers to provide the majority of services necessary to serve the Authority's customers. Below is a summary of the Authority's primary operating agreements:

Amended and Restated Operations Services Agreement: Effective January 1, 2014, PSEG Long Island, a wholly owned subsidiary of Public Service Enterprise Group (PSEG) fully dedicated to the Authority's Long Island operations, provides operations, maintenance and related services for the T&D system under the Amended and Restated Operations Services Agreement (A&R OSA). The A&R OSA shifted major operational and policy-making responsibilities for the T&D system, including significant responsibilities relating to capital expenditures and emergency response, from the Authority to PSEG Long Island. The A&R OSA expires December 31, 2025 and includes a provision that if PSEG Long Island achieves certain levels of performance based on criteria during the first 10 years, the parties will negotiate an eight year extension on substantially similar terms and conditions. PSEG Long Island is paid a management fee and may earn incentives related to specified performance metrics. In addition, essentially all costs of operating and maintaining the Authority's T&D system incurred by PSEG Long Island are passed through to and paid for by the Authority.

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

Fuel Management Agreement (FMA) and Power Supply Management Agreement (PSM): PSEG Energy Resources and Trade LLC (PSEG ER&T) provides fuel management services for both the GENCO generating facilities and the non-GENCO units for which the Authority is responsible for providing fuel. Certain other services related to power supply management and commodity activities are also provided by PSEG ER&T. The agreements with PSEG ER&T expire December 31, 2025 and are also subject to extension.

(2) Summary of Significant Accounting Policies

(a) Reporting Entity

The Authority complies with all applicable pronouncements of Governmental Accounting Standards Board (GASB). In accordance with GASB No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements*. The operations of the Authority are presented as an enterprise fund following the accrual basis of accounting in order to recognize the flow of economic resources.

The Authority's reporting entity is comprised of itself and (i) its operating subsidiary the Long Island Lighting Company (LILCO), a wholly owned subsidiary of the Authority doing business as "LIPA" and Power Supply Long Island, and the (ii) UDSA. All significant transactions between the Authority, LIPA and the UDSA have been eliminated. The Authority and its blended component units are referred to collectively as the "Authority" in the financial statements.

(b) Estimates

The accompanying financial statements were prepared in conformity with U.S. generally accepted accounting principles, which require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(c) Reclassifications

To achieve conformity and comparability, the Authority has reclassified certain amounts in prior year financial statements where applicable.

(d) Immaterial correction of prior period classification of restricted cash and net position

The classification of restricted cash related to grants received in advance ($448 million) has been corrected on the statement of net position as of December 31, 2014 from restricted current assets to restricted non-current assets. In addition, net position has been corrected to reclassify $528 million from restricted to unrestricted net position and $15 million has been reclassified from net investment in capital to unrestricted net position. These reclassifications do not impact total net position as of December 31, 2014 and are not considered material to any previously issued financial statements.

(e) Cash, cash equivalents, restricted cash and investments

Cash, cash equivalents and restricted cash include all highly liquid financial instruments with a maturity of three months or less when purchased.

Funds held by the Authority are administered in accordance with the Authority's investment guidelines pursuant to Section 2925 of the New York State Public Authorities Law. These guidelines comply with the New York State Comptroller's investment guidelines for public authorities. Investments' carrying values are reported at fair market value.

Certain amounts have also been restricted for specific purposes. For a further discussion, see note 10.

(f) Counterparty Collateral

The Authority and its counterparties require collateral posting for mark-to-market valuations that exceed established credit limits. At December 31, 2015 and 2014, the Authority was required to post $48.4 million and $4.5 million, respectively, of collateral to various counterparties, which is recorded as a current asset. One of the Authority's counterparties was required to post $1.1 million of collateral at December 31, 2014 to the Authority, which is recorded in current liabilities.

(g) Fuel Inventory

The Authority owns the fuel oil used in the generation of electricity at the facilities under contract to it. Fuel inventory represents the value of low sulfur and other liquid fuels that the Authority had on hand at each year-end in order to meet the demand requirements of these generating stations. Fuel inventory is valued using the weighted average cost method. At the time of consumption, an expense is recorded at the weighted average cost.

(h) Material and Supplies Inventory

The materials and supplies inventory supports the operations of maintaining the T&D system. The inventory is accounted for on a first in first out (FIFO) basis of accounting. During the year there were no significant write-downs for obsolescence.

The Authority owns 18% of the material and supplies inventory needed to support the operation of the Nine Mile Point Unit 2 (NMP2) nuclear power station. As of December 31, 2015 and 2014, the value of the NMP2 inventory totaled approximately $12 million and $9 million, respectively.

(i) Other Receivables and Long-Term Receivables

The current portion of other receivables, as of December 31, 2015 and 2014, included $10 million and $80 million, respectively, for a Community Development Block Grant (CDBG), both of which were received in their respective subsequent year.

The long-term portion of other receivables represents the net present value related to the reimbursable costs to construct the interconnection facilities related to the Neptune cable, which is to be paid to the Authority over a 20-year period.

(j) Unrealized Charges

Unrealized charges consist primarily of the ineffective balance of interest rate and commodity derivative instruments.

(k) Acquisition Adjustment

The Acquisition Adjustment, an intangible asset, represents the difference between the purchase price paid and the net assets acquired from LILCO and is being amortized and recovered through rates on a straight-line basis through 2026.

(l) Borrowings

Borrowings represent the unamortized balance of cash premiums received at the time of entering into certain financial derivative instruments. The Authority is amortizing such premiums over the life of the instrument in accordance with GASB No. 53, *Accounting and Financial Reporting for Derivative Instruments* (GASB No. 53).

(m) Commodity and Financial Derivative Instruments

Represents the amount that the Authority believes it would be required to pay in order to terminate its commodity and financial derivative instruments as of December 31, 2015 and 2014, which approximates fair value.

(n) Capitalized Lease Obligations

Capitalized lease obligations represent the net present value of various contracts for the capacity and/or energy of certain generation and transmission facilities. Upon satisfying the capitalization criteria, the net present value of the contract payments is included in both Utility Plant and Capital Lease Obligations.

The Authority recognizes in fuel and purchased power expense an amount equal to the contract payment of the capitalized leases, as allowed through the ratemaking process. The value of the asset and the obligation is reduced each month so that the statements of net position properly reflect the remaining net present value of the asset and obligation at each month end.

For a further discussion on the capitalization of capacity and/or energy contracts, see note 14.

(o) Long-Term Liabilities and Unrealized Credits

Long-term liabilities and unrealized credits consists primarily of the Authority's unfunded other post-employment benefit obligation for Authority employees and unsettled insurance reimbursements.

(p) Claims and Damages

Losses arising from claims including workers' compensation claims, property damage, and general liability claims are partially self-insured. Reserves for these claims and damages are based on, among other things, experience and expected loss.

(q) Revenues

Operating revenues are comprised of cycle billings for electric service rendered to customers based on meter reads and the accrual of revenues for electric service rendered to customers not billed at month-end. The Authority accrues unbilled revenues by estimating unbilled consumption at the customer meter. Unbilled revenue totaled $196 million and $220 million as of December 31, 2015 and 2014, respectively.

(r) Depreciation and Amortization

The provisions for depreciation for utility plant result from the application of straight-line rates determined by an age life studies of assets in service. The rates are applied to groups of depreciable properties. The average composite depreciation rate is 1.63% and 1.65% for December 31, 2015 and 2014, respectively.

Leasehold improvements are being amortized over the lesser of the life of the assets or the term of the lease, using the straight-line method. Property and equipment are being depreciated over its estimated useful life using the straight-line method.

During 2014, the Authority completed a depreciation study that identified an excess accumulated reserve imbalance and implemented depreciation rates that amortize that imbalance over the remaining life of the assets. At year-end 2015, in accordance with the Three Year Rate Plan adopted by the Authority's Board in December 2015 (as discussed in note 3), the unamortized excess reserve balance was reclassed from the accumulated depreciation reserve and recorded as a regulatory liability in accordance with the DPS Rate Plan Recommendation. This regulatory liability was then netted against the Acquisition Adjustment Asset to reduce the remaining unamortized balance of the Acquisition Adjustment by $718 million. Effective January 1, 2016, the Authority will adopt depreciation rates that reflect the remaining net book value and useful lives of the plant assets.

(Amounts in thousands, unless otherwise stated)

The following estimated useful lives as determined by the updated depreciation study are used for utility property:

Category	Useful life
Generation – nuclear	46–54 years
Transmission and distribution	40–75 years
Common	5–55 years
Nuclear fuel in process and in reactor	6 years
Generation assets under capital lease	10–25 years

(s) Asset Retirement Obligation

The Authority, as an 18% owner of NMP2, has a legal obligation to fund its share of the decommissioning costs of the nuclear power plant. The legal obligation associated with the retirement of a tangible, long lived asset resulting from the acquisition, construction, development and/or normal operation of the asset is referred to as an ARO. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and method of settlement. The ARO is continually reviewed for adequacy and was updated in 2015 based on a third party engineering study performed in 2014.

The Authority also has an ARO related to certain of its T&D utility assets. Although no legal requirement exists to remove such assets from service, a "conditional" obligation is present based on the premise that eventually these assets will be removed from service as a result of deterioration. Accordingly, the Authority established a liability for the portion of the costs that are attributable to the "conditional" obligation. This ARO is also continually reviewed for adequacy and was updated during 2015.

A summary of the ARO activity of the Authority for the years ended December 31, 2015 and 2014 is included below:

		2015	2014
Asset retirement obligation:			
Beginning balance	$	66,414	84,828
Change due to updates		(7,310)	(22,952)
Accumulated depreciation		—	155
Accretion expense		3,802	4,383
Balance at December 31	$	62,906	66,414

(t) Long-Lived Assets

Long-lived assets and purchased intangibles subject to amortization are reviewed for impairment whenever events or changes in circumstances indicate that there is a significant unexpected decline in the service utility of a capital asset. Impairment, if any, would be measured using one of three approaches that best reflect the decline in service utility.

(u) Payments-in-Lieu-of-Taxes

The Authority makes payments-in-lieu-of-taxes (PILOTS) for certain taxes previously paid by LILCO, including gross income, gross earnings, property, Metropolitan Transportation Authority, and certain taxes related to fuels used in utility operations. In addition, the Authority has entered into various PILOT arrangements for property it owns, upon which merchant generation and transmission is built. Effective January 1, 2014, the Reform Act eliminated the Authority's obligation to pay gross earnings tax.

(v) Allowance for Borrowed Funds Used During Construction

The allowance for borrowed funds used during construction (AFUDC) is the net cost of borrowed funds used for construction purposes. AFUDC is computed monthly on a portion of construction work in progress, and is shown as a net reduction in interest expense. The AFUDC rates were 4.84% and 4.67% for the years ended December 31, 2015 and 2014, respectively.

(w) Income Taxes

The Authority is a political subdivision of the State and, therefore, is exempt from Federal, state, and local income taxes.

(x) Recent Accounting Pronouncements

In February 2015, GASB issued Statement No. 72, Fair Value Measurement and Application, which addresses accounting and financial reporting issues related to fair value measurements. The requirements of this Statement will enhance comparability of financial statements among governments by requiring measurement of certain assets and liabilities at fair value using a consistent and more detailed definition of fair value and accepted valuation techniques. This Statement also will enhance fair value application guidance and related disclosures in order to provide information to financial statement users about the impact of fair value measurements on a government's financial position. GASB No. 72 will take effect for periods beginning after June 15, 2015.

In June 2015, GASB issued Statement No. 73, Accounting and Financial Reporting for Pensions and Related Assets That Are Not within the Scope of GASB No. 68, and Amendments to Certain Provisions of GASB No. 67 and 68. GASB No. 73 (the Pension Statements) generally aligns the reporting requirements for pensions and pension plans not covered in GASB No. 67 and 68 with the reporting requirements in GASB No. 68. This Statement is effective for fiscal years beginning after June 15, 2015—except those provisions that address employers and governmental nonemployer contributing entities for pensions that are not within the scope of GASB No. 68, which are effective for fiscal years beginning after June 15, 2016.

In June 2015, GASB issued Statement No. 74, Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans (OPEBs). This Statement will take effect for periods beginning after

June 15, 2016. GASB also issued Statement No. 75, Accounting and Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans. This Statement will take effect for period beginning after June 15, 2017. GASB No. 74 and No. 75 (the OPEB Statements) address (1) financial reports of defined benefit OPEB plans that are administered through trusts that meet specified criteria and (2) reporting by governments that provide OPEB to their employees and for governments that finance OPEBs for employees of other governments.

In June 2015, GASB issued Statement No. 76, The Hierarchy of Generally Accepted Accounting Principles for State and Local Governments. The objective of this Statement is to identify the hierarchy of generally accepted accounting principles (GAAP). The "GAAP hierarchy" consists of the sources of accounting principles used to prepare financial statements of state and local governmental entities in conformity with GAAP and the framework for selecting those principles. This Statement reduces the GAAP hierarchy to two categories of authoritative GAAP and addresses the use of authoritative and nonauthoritative literature in the event that the accounting treatment for a transaction or other event is not specified within a source of authoritative GAAP. This Statement is effective for reporting periods beginning after June 15, 2015.

In December 2015, GASB issued Statement No. 78, Pensions Provided through Certain Multiple-Employer Defined Benefit Pension Plans. This Statement amends the scope and applicability of GASB No. 68 to exclude pensions provided to employees of state or local governmental employers through a cost-sharing multiple-employer defined benefit pension plan that (1) is not a state or local governmental pension plan, (2) is used to provide defined benefit pensions both to employees of state or local governmental employers and to employees of employers that are not state or local governmental employers, and (3) has no predominant state or local governmental employer. This Statement establishes requirements for recognition and measurement of pension expense, expenditures, and liabilities; note disclosures; and required supplementary information for pensions that have the characteristics described above. This Statement is effective for reporting periods beginning after December 15, 2015.

In December 2015, GASB issued Statement No. 79, Certain External Investment Pools and Pool Participants. This Statement permits certain external investment pools to use amortized cost to measure pool investments. This Statement is effective for reporting periods beginning after June 15, 2015, except for certain provisions on portfolio quality, custodial credit risk, and shadow pricing. Those provisions are effective for reporting periods beginning after December 15, 2015.

In January 2016, GASB issued Statement No. 80, Blending Requirements for Certain Component Units—an amendment of GASB No. 14. This Statement changes how certain component units incorporated as not-for-profit corporations should be presented in the financial statements of the primary state or local government. Specifically, such component units must be "blended into the primary state or local government's financial statements in a manner similar to a department or activity of the primary government." This Statement is effective for reporting periods beginning after June 15, 2016.

The Authority is currently evaluating the impact of these statements on our consolidated financial statements, and does not expect a material impact upon adoption.

(3) Rate Matters

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. 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 is empowered under its enabling statute to set rates for electric service in the Service Area without obtaining the approval of the Public Service Commission (PSC) or its staff arm, the DPS, or any other State regulatory body. Under the Reform Act, on or before February 1, 2015, the Authority and PSEG Long Island were required to submit to the DPS a three-year rate proposal for rates and charges to take effect on or after January 1, 2016. After the 2016-2018 period, the Authority and PSEG Long Island are only required to submit a proposed rate increase for DPS review if it would increase the rates and charges by an amount that would increase the Authority's total annual revenues by more than 2.5%. In addition, the Authority may place rates in effect on an interim basis, and such interim rates are subject to prospective adjustment only. The Authority's Board retains final rate setting power.

On January 30, 2015, a Three Year Rate Plan for the period 2016-2018 was submitted by PSEG Long Island and the Authority for review by DPS. Evidentiary hearings were held and other parties had the opportunity to present evidence and cross-examine the Authority, PSEG Long Island, and DPS witnesses. All of this information was available to the DPS for their review. Following the review of the Rate Plan by DPS, approval was required by the Authority's Board. 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, the Reform Act required that the Board implement the Three Year Rate Plan set forth in the DPS Recommendation.

PSEG Long Island and the Authority's original submission proposed rate increases of $72.7 million, $74.3 million, and $74.3 million for the years 2016, 2017 and 2018, respectively, for a cumulative revenue requirement increase of $441.0 million over the three year period. At those proposed levels, the Authority's overall electric revenues, including power supply costs, would have increased by approximately 2.0% each year or a cumulative 6.0% over the three year period. Throughout the proceeding, PSEG Long Island, the Authority, the DPS staff, and other parties proposed and updated revenue requirement positions. PSEG Long Island and the Authority's incremental rate request as of the time of the DPS Recommendation in September 2015 was $58.2 million, $72.2 million, and $68.1 million for the years 2016, 2017 and 2018, respectively, for a cumulative increase of $387.2 million or 5.4%. The DPS Recommendation was for the Authority to set rates designed to increase revenues by $30.4 million, $77.6 million, and $79.0 million, respectively, for a cumulative increase of $325.4 million or 5.0%. At those proposed levels, the Authority's overall electric revenues, including power supply costs, would increase by approximately 0.8%, 2.1%, and 2.1%, respectively.

The Three Year Rate Plan incorporated a new Board-adopted financial policy that seeks to reduce the portion of the Authority's capital plan funded by debt to 64% or less and raise the Authority's credit ratings to A2 by Moody's Rating Service, A by Standard and Poor's, and A by Fitch Ratings over five years. To achieve these goals, the Rate Plan adopted the "public power model" of rate-setting proposed by PSEG Long Island and the Authority staff, and recommended by the DPS, which makes use of the debt service coverage method of determining revenue requirements. For the Authority this entails transitioning from the historic use of a $75 million budget for net income to budgeting to achieve fixed obligation coverage targets (including capitalized leases) on Authority issued debt of 1.20x, 1.30x, 1.40x in 2016, 2017, and 2018, respectively (and 1.45x in 2019 after the Three Year Rate Plan). When the UDSA restructuring bonds are included, these coverage ratio targets are a minimum of 1.15x, 1.20x and 1.25x in 2016, 2017, and 2018, respectively. The Authority's methodology for calculating the fixed obligation coverage ratio excludes certain specified non-cash items from expenses. Depreciation expense, amortization of the Acquisition Adjustment and of other regulatory assets, as well as the difference between accrual expense and actual required cash contributions to PSEG Long Island pension and OPEBs, are non-cash expenses excluded from the revenue requirements calculation. The Authority cannot predict whether any such targets will be realized.

The DPS Recommendation also includes an update process, referred to as Staged Updates, in December 2015, 2016 and 2017 to adjust delivery rates higher or lower to reflect measurable changes in certain specified projected costs, and a cost reconciliation mechanism, referred to as the Delivery Service Adjustment, to reconcile certain specified projected costs to actual costs in each year.

The Staged Updates provide for updating electric rates at the beginning of each year for items that are subject to variability due to external factors including, among others: debt service (variances in interest rates, capital expenditures and savings derived from the UDSA financings) (also subject to the Delivery Service Adjustment); certain components of the costs of the A&R PSA with NGRID (variances in property taxes and pensions and benefits settlements (also subject to the Delivery Service Adjustment); property-based PILOTs; and certain other legal or regulatory changes. Projections will be updated each autumn, subject to DPS review, and presented to the Authority's Board as part of the annual budget process. The Authority's 2016 budget process resulted in proposed rates implemented through the initial Staged Update that lowered the increase in revenues from what is set forth in the DPS Recommendation by $10.3 million in 2016 (from $30.4 million to $20.1 million), $12.4 million in 2017 (from $77.6 million to $65.2 million) and $15.3 million in 2018 (from $79.0 million to $63.7 million), which lowered customer bills by a cumulative $38.0 million as a result of more up-to-date assumptions regarding future expenses.

The Delivery Service Adjustment provides cost recovery for certain items that can vary due to external factors, which items include, among others: debt service (variances in interest rates, capital expenditures and savings derived from the UDSA financings); all components of the Authority's A&R PSA with NGRID and operating costs related to the Authority's ownership of NMP2; and storm expenditures (variances from the approximately $50 million per year budgeted for storm expenses in base rates). The Delivery Service Adjustment is expected to be calculated through the end of September each year, which allows for the bill impact to be known in advance of annual budget approval. Any adjustment would be reviewed by DPS and implemented on the following January 1st.

The DPS Recommendation affirmed the Authority's use of a revenue decoupling mechanism (RDM). The Authority's Board initially modified its tariff to establish a RDM in March 2015. All six of the major New York state electric utilities have RDMs within their tariffs for delivery service. Mechanically, RDMs function by comparing actual revenues with authorized revenues and crediting (or collecting) any differences to (or from) customers in a subsequent period; it is intended to cover all sources of variances in delivery service revenues including, among other things, any net lost revenues attributable to the implementation of energy efficiency or net metering programs, any revenue variances caused by hotter or colder than normal weather, and revenue variations that result from changes in economic conditions.

The Authority's Board met on December 16, 2015 and adopted a resolution implementing the DPS Recommendation by, among other things, approving the proposed 2016 Operating and Capital Budgets, approving revisions to the base rates for delivery service within the tariff designed to recover the level of revenue with the budgets that is consistent with the DPS Recommendation, establishing the Delivery Service Adjustment within the tariff, and adopting the financial policy that was applied in the Three Year Rate Plan described above.

In addition to the items discussed above, the Authority's tariff also includes: (i) the Fuel and Purchased Power Cost Adjustment (FPPCA), referred to as the Power Supply Charge, to allow for adjustments to customers' bills to reflect changes in the cost of fuel and purchased power and related costs; (ii) a PILOTS recovery rider to allow rate adjustments to accommodate changes in revenue-based PILOTS; (iii) a rider providing for the recovery of costs associated with the Shoreham Property Tax Settlement; (iv) a rider for the Authority's distributed energy resources program; (v) a rider providing for the collection of the Temporary State Assessment and New York State assessment imposed by the New York State Legislature; and (vi) a visual benefit assessment for certain customers in the Town of Southampton.

Utility Debt Securitization Authority Restructuring Charges

Part B of the Reform Act created the Securitization Law, which established the UDSA to permit the issuance of restructuring bonds to allow the Authority to retire a portion of its outstanding indebtedness in order to provide savings to the Authority's customers as measured on a net present value basis. The Securitization Law, as amended, allows for a total issuance of up to $4.5 billion of UDSA restructuring bonds.

Each issuance of restructuring bonds is separately secured by distinct collateral pursuant to a new financing order. Each such financing order authorizes restructuring bonds to be repaid pursuant to that financing order by an irrevocable contract right to impose, bill, and collect a nonbypassable consumption-based Restructuring Charge from all existing and future retail electric customers taking electric transmission or distribution service within the Service Area from the Authority or any of its successors or assignees.

On December 18, 2013, pursuant to Financing Order No. 1 adopted on October 3, 2013, the UDSA issued approximately $2.02 billion of restructuring bonds. On June 26, 2015, the Authority's Board adopted Financing Orders No. 2, No. 3 and No. 4, which allow the UDSA to issue additional restructuring bonds prior to December 31, 2016. All such financing orders are substantively the same, and each financing order permits the UDSA to issue additional restructuring bonds in an aggregate amount not to exceed the amount authorized by the Securitization Law.

On October 27, 2015, pursuant to Financing Order No. 2, the UDSA issued approximately $1.002 billion of 2015 Restructuring Bonds. The issuance of the 2015 Restructuring Bonds reduced the available amount of restructuring bonds permitted to be issued by the Securitization Law and pursuant to Financing Orders No. 3 and No. 4 to approximately $1.476 billion.

To pass through the benefits of securitization to customers, the Authority has modified its rate structure to create a restructuring offset charge, which is an amount equal to and opposite the Restructuring Charge, so that the customer bill is less than it would have been absent the sale of restructuring bonds. The restructuring offset charge will be adjusted coincident with changes to the Restructuring Charge to maintain that equality.

(4) Regulatory Accounting

Below are the summary of the Authority's regulatory assets and liabilities:

(a) A&R OSA – Employee Retirement Benefits

The Authority is responsible for reimbursing PSEG Long Island for their retirement benefit costs associated with the PSEG Long Island workforce. The retirement benefit plans are owned, sponsored, and the legal obligation of PSEG Long Island. However, in most cases, PSEG Long Island employee compensation costs are a contractual cost of the Authority under the A&R OSA, including the cost for these retirement benefits (and any required pre-funding of such benefits).

The PSEG Long Island workforce includes both former NGRID employees that were electric-servicing employees under the expired Management Services Agreement (MSA) (approximately 1,950 employees) (referred to as "transitioned employees") and newly hired employees. PSEG Long Island recognizes the assets and liabilities associated with the retirement benefit plans; however, they also recognize a receivable from the Authority for the unfunded portion of any liabilities due to the Authority's contractual obligation to fund these employee costs.

A significant portion of this contractual liability resulted from the transitioned employees being protected against benefit losses from the Authority's change in service providers from NGRID to PSEG Long Island. The PSEG Long Island retirement plans ensure that transitioned employees earn a retirement benefit that, when combined with their accrued NGRID benefits, will be equal to the benefit they would have received had the transitioned employees remained employees of NGRID. This provision created a prior service cost liability totaling $442 million at the beginning of the A&R OSA on January 1, 2014.

The balance of the A&R OSA – Employee Retirement Benefits regulatory asset as of December 31, 2015 and 2014, represents those costs which have been incurred but not yet collected from customers. This amount will be different from the Authority's liability to PSEG Long Island due to differences between funding and recovery levels. Additionally, the Authority set aside certain funds in an OPEB

Account (see footnote 10) to pay future retirement benefit costs to PSEG Long Island, such amounts have been recovered from customers but not yet paid to PSEG Long Island.

These retirement benefit obligations are for future cash outlays that will be incurred as the PSEG Long Island employees receive retirement benefits and are therefore estimates of such costs. Differences between the amounts collected from customers and the amounts owed to PSEG Long Island for these benefits may arise from changes in asset values, plan amendments, interest rates, and actuarial assumptions, among other factors, which would be reflected in the balance of the regulatory asset.

(b) Shoreham Property Tax Settlement (Settlement)

In January 2000, the Authority reached an agreement with Suffolk County, the Town of Brookhaven, the Shoreham-Wading River Central School District, the Wading River Fire District and the Shoreham-Wading River Library District (which was succeeded by the North Shore Library District) (collectively, the Suffolk Taxing Jurisdictions) and Nassau County regarding the over assessment of the Shoreham Nuclear Power Station. Under the terms of the agreement, the Authority was required to issue $457.5 million of rebates and credits to customers over a five-year period which began May 29, 1998. In order to fund such rebates and credits, the Authority used the proceeds from the issuance in May 1998 of its Capital Appreciation Bonds, Series 1998A Electric System General Revenue Bonds totaling $146 million and the issuance in May 2000 of approximately $325 million of Electric System General Revenue Bonds, Series 2000A.

As provided under the Settlement, beginning in June 2003, Suffolk County customers' bills include a surcharge (the Suffolk Surcharge) to be collected over the succeeding approximate 25-year period to repay the debt service and issuance costs on the bonds issued by the Authority to fund the Settlement as well as the cost of pre-funding certain rebates and credits.

As rates are established at a level sufficient to recover all such costs identified above, the Authority recorded a regulatory asset. The balance of the Shoreham Property Tax Settlement regulatory asset as of December 31, 2015 and 2014 was approximately $491 million and $503 million, respectively. The balance represents rebates and credits issued to customers, costs of administering the program plus annual debt service costs on the bonds identified above, less surcharges collected since 2003.

(c) Employee Benefit Plan Settlement

The MSA between the Authority and NGRID provided, among other things, that upon termination of the MSA, when a third party succeeded NGRID as the service provider, the successor would assume the rights and obligations of NGRID regarding certain employee benefit plan liabilities. The A&R OSA with PSEG Long Island, however, did not require PSEG Long Island to assume the employee benefit plan assets and liabilities related to the MSA, which were co-mingled with those of other NGRID employees.

On December 31, 2013, the Authority signed an Employee Benefit Plan Settlement with NGRID and its affiliates. The Settlement provided for a $91.5 million cash payment and the release of NGRID's payment obligations for an approximate $155 million promissory note due to the Authority. The settlement resolved the parties' respective employee benefit plan funding obligations for NGRID's electric-serving employees. The balance subject to recovery after applying carrying charge accruals, totaled $216 million. The Authority's Board approved deferred recovery of such costs from customers which began on January 1, 2016 over a 10-year period, the remaining term of the A&R OSA, as virtually all former employees of NGRID covered by these plans have been transitioned to PSEG Long Island and continue to serve electric customers.

(d) Revenue Decoupling Mechanism (RDM)

The RDM, which was implemented on April 1, 2015, ensures that only approved revenues for delivery service are collected from customers. The RDM compares actual revenues with authorized revenues and credits (or collects) any differences to (or from) customers in a subsequent period. It is intended to cover all sources of variances in delivery service revenues including, among other things, any net lost revenues attributable to the implementation of energy efficiency or net metering programs, any revenue variances caused by hotter or colder than normal weather, and revenue variations that result from changes in economic conditions.

As of December 31, 2015, the delivery service booked revenues were lower than the approved level resulting in a collection totaling approximately $17 million to be collected from customers over a six-month period beginning in March 2016.

(e) New York State Temporary Energy and Utility Conservation Assessment

As a result of an amendment to the Public Service Law effective April 1, 2009, the Authority was required to collect from all customers a special assessment to be paid directly to the State for a five year period that began in 2009. Subsequent legislation extended the assessment at its full rate through March 2015 and at declining percentages each subsequent year such that it phases out by the end of calendar year 2017.

(f) Transition Costs – Operations Services Agreement

The Authority deferred costs incurred in 2012 and 2013 related to the transition of operations services from NGRID to PSEG Long Island, which costs were to be amortized over the term of the A&R OSA. PSEG Long Island performed a variety of specified activities in order to position itself to assume responsibility to provide operations services upon assuming the responsibility on January 1, 2014. The costs related to those activities were classified as a regulatory asset.

During 2015, the Authority's Board approved eliminating such deferred transition costs and any further recovery from customers.

(g) Debt Issuance Costs

GASB No. 65 requires that debt issuance costs be expensed in the current financial period. As the Authority's rates provide recovery for debt issuance costs as a component of the Authority's revenue requirement on a systematic basis over the life of the debt, the Authority's Board approved reclassifying the unamortized balance of debt issuance costs incurred to a regulatory asset to be collected over the life of the debt issues to which they relate.

(h) Enterprise Resource Planning (ERP system) Costs and Outage Management System (OMS)

PSEG Long Island implemented a long term ERP solution in 2015 to allow the PSEG Long Island T&D business to separate from the NGRID ERP system and financial functions. The Authority chose to leverage the existing PSEG ERP system, incorporating PSEG Long Island functions into the PSEG platform rather than creating a new standalone PSEG Long Island ERP system. Utilizing the existing platform allowed PSEG Long Island to transition to a new ERP solution significantly earlier than planned, reduce cost, and minimize business risk.

PSEG Long Island also completed a transition to the PSEG OMS system to track and manage repair of electric system outages. Transition to the established PSEG OMS system allowed for an expedited implementation of 13 months. This new system improves the ability to identify and manage outage conditions and communication of outage information to customers. In the event the A&R OSA is terminated early and PSEG Long Island is no longer the service provider, the OMS system will be available for use for up to 2 years after such termination to permit transition to an alternative system.

As these assets are not owned by the Authority or PSEG Long Island, but the costs incurred are solely for the benefit of PSEG Long Island, the costs of these projects are recognized as regulatory assets for recovery over the remaining life of the A&R OSA beginning in 2015, which is consistent with their expected useful lives.

As of December 31, 2015 and 2014, deferred costs remaining for the transition to the PSEG ERP and PSEG OMS systems totaled $73 million and $69 million, respectively.

(i) Fuel and Purchased Power Costs Recoverable

The Authority's tariff includes a fuel recovery provision – the FPPCA or Power Supply Charge – that provides for the recovery of fuel and purchased power costs on a monthly basis. In no event, however, may the Authority recover an amount that exceeds fuel and purchased power costs incurred. For the year ended December 31, 2015 and 2014, actual fuel and purchased power costs were below amounts recovered in the FPPCA. As a result, a regulatory liability totaling $30 million and $40 million, respectively were recorded and such amounts were returned to customers during 2016 and 2015, respectively, as prescribed by the monthly collection method.

Also recorded as recoverable fuel and purchased power costs are amounts incurred related to various energy projects, the amortization of which is charged to fuel and purchased power costs over the period of benefit (the life of the power purchase agreement) totaling $37 million and $40 million as of December 31, 2015 and 2014, respectively.

(j) Transition Costs - Power Supply Management

The Authority's Board approved deferral of the transition costs associated with transitioning to the power supply management contract with PSEG ER&T. Collection of these costs totaling $19 million will be recovered over an eleven-year period, beginning January 1, 2015, coincident with the contract beginning January 1, 2015 and expiring December 31, 2025, as approved by the Authority's Board. As of December 31, 2015, the remaining balance of such costs totaled $17 million.

(k) Southampton Visual Benefit Assessment

The Authority has recorded the incremental costs incurred to bury a portion of a transmission cable routed through the Town of Southampton (Town), which will be recovered from certain customers of the Town over a period of 20 years that began in 2009.

(5) Deferred Outflow and Deferred Inflow of Resources

GASB No. 65, *Items Previously Reported as Assets and Liabilities*, establishes accounting and financial reporting standards that reclassify certain items that were previously reported as assets and liabilities, and recognizes them as deferred outflows of resources (expenses or expenditures) and deferred inflows of resources (revenues). The following items are classified as deferred outflows of resources or deferred inflows of resources:

(a) Losses on Refunding Debt

Losses on refunding debt represent the difference between the reacquisition price and the carrying amount of the refunded debt. Prior to GASB No. 65, these losses were a contra-liability to debt. This deferred outflow is amortized as a component of interest expense over the shorter of the life of the old or new debt.

(b) Change in Fair Market Value of Derivative Instruments

The accumulated changes in the fair value of hedging derivative instruments which are deemed effective are reported as deferred outflows or deferred inflows. Under hedge accounting, the changes in the fair value of a hedging derivative instrument, in asset or liability positions, are reported as a deferred inflow of resources or deferred outflow of resources, respectively, on the Statements of Net Position.

As the Authority follows GASB No. 62, any changes in ineffective investment derivative instruments are reported as unrealized charges. The change in fair value of investment derivative instruments are reported as unamortized charges, as the Authority's Board has authorized the deferral of these unrealized gains and losses until realized, which corresponds to the period when they are recovered in rates.

(c) Regulatory Credits - grants

The Authority has received grants for storm restoration and storm hardening in excess of that which it has paid to date. This advance has been recorded as a deferred inflow, as these funds will be used to pay vendors for storm restoration once all disputed amounts are finalized and for T&D storm hardening expected to be completed over the next several years. In 2014, the Board authorized the deferral of grant income as a regulatory credit for grants related to capital expenditures for storm hardening. Thus, this regulatory credit will be deferred to match the depreciable lives of the related capital assets so that the grant income is recognized over the same time period as the depreciation expense on the future capital assets.

(d) Change in Fair Market Value of NMP2 Decommissioning Trust

The Authority maintains a Trust for the decommissioning of NMP2. The decommissioning funds are reported at their fair market value and any unrealized gains or losses are recognized as a component of deferred inflows in accordance with the Authority's ratemaking process and have no impact to the Authority's net position. For a further discussion on the Authority's NMP2 decommissioning obligations and related funding see note 9.

(e) Amounts related to pension expense

In accordance with GASB No. 68, the Authority reports the difference between expected and actual experience, the net difference between projected and actual investment earnings on pension plan investments, changes in proportion and differences between employer contributions and proportionate share of contributions, changes in proportion, and the Authority's contributions to the pension system subsequent to the measurement date as a deferred inflow or outflow of resources.

(6) FEMA Grants

In 2012, Superstorm Sandy caused significant damage to predominantly all of the Authority's Service Area resulting in the declaration of a federal major disaster area and making the Authority eligible for FEMA grants for recovery. The Authority's total costs for restoration, which included labor, material, equipment, travel and incidental expenses associated with assistance from utilities across the nation, totaled $677 million. Any amounts not recovered through insurance including the deductible, will be analyzed for reimbursement eligibility under the FEMA claim. Substation work is expected to be completed in 2018 and is being capitalized as incurred.

During 2014, the Authority and FEMA signed a Letter of Undertaking (LOU) that provides for a Public Assistance (PA) grant authorized under Section 428 of the Stafford Act (428 Grant Agreement). Funds from the 428 Grant Agreement will reimburse the Authority for 90% of its eligible repair/restoration costs and certain storm hardening and future mitigation projects to strengthen the electric grid on Long Island, for a total eligible reimbursement of $1.29 billion (90% of $1.43 billion LOU).

As of December 31, 2015, the Authority has received $1.11 billion under the 428 Grant Agreement, of which the Authority reimbursed its treasury for funds expended to date totaling $637 million, and transferred the balance of $474 million to a segregated account to be used to pay remaining unpaid storm restoration costs and to fund future storm hardening and mitigation efforts.

In September 2014, the Authority signed a Community Development Block Grant (CDBG) agreement for $143.2 million representing an amount equal to the 10% nonfederal match of the FEMA grants associated with Superstorm Sandy. Under the terms of this CDBG grant, funds are provided to compensate for the nonfederal match of certain declared weather events including Superstorm Sandy, Hurricane Irene, and Snowstorm Nemo as well as certain storm mitigation protective measures. This grant is funded by the United States Department of Housing and Urban Development (HUD). In January 2015, the Authority received $80 million, $51 million related to Superstorm Sandy damages and $29 million relating to Hurricane Irene damages incurred in 2011. In January 2016, the Authority received an additional $10.3 million related to damages incurred as a result of Hurricane Irene.

(7) Derivative Instruments

The Authority uses derivative instruments in its normal course of business to attempt to manage the impact to its customers of interest rate changes and market price fluctuations for the purchase of fuel oil, natural gas and electricity. The Authority does not use derivative instruments for trading or speculative purposes. These contracts are evaluated pursuant to GASB No. 53 to determine whether they meet the definition of derivative instruments, and if so, whether they effectively hedge the expected cash flows associated with interest rate and commodity price risk exposures. The fair values of the Authority's derivatives as defined by GASB No. 53 are reported on the Statements of Net Position as either Commodity Derivative Instruments or Financial Derivative Instruments.

The Authority applies hedge accounting for derivative instruments that are deemed effective under GASB No. 53. Under hedge accounting, changes in the fair value of such hedging derivative instrument is a component of deferred inflow or deferred outflow on the Statements of Net Position until the contract is settled or hedge accounting is terminated. Derivative instruments that do not meet the definition of a hedging derivative instrument are economic hedges, intended to mitigate exposure to fluctuations in interest rates or commodity prices and are referred to as investment derivative instruments. Changes in the fair value of investment derivative instruments are deferred until settled or terminated in accordance with the Authority's ratemaking process.

All settlement payments or receipts for hedging derivative instruments are recorded as either fuel and purchased power expense or interest expense for interest rate derivatives on the Statements of Revenues, Expenses and Changes in Net Position in the period settled. All settlement payments or receipts related to investment derivative instruments are recorded as interest expense or as fuel and purchased power expense in the Statements of Revenues, Expenses and Changes in Net Position in the period incurred.

The Authority's interest rate derivative contracts are transacted over-the-counter and are valued based on exchange-traded contracts with readily available quoted market prices. For the interest rate derivatives where there is no external source or observable market price quotation, values are based on various valuation techniques, including, but not limited to models internal to the Authority's financial advisor and based on extrapolation of observable market data with similar characteristics. The Authority's fuel and purchased power derivative contracts are transacted both over-the-counter and through clearing exchanges and the valuations are based upon price quotes from exchanges and third party brokers. For both the interest rate derivative contracts and the fuel and purchased power derivative contracts, the Authority's practice is to not discount the fair value of each contract using an interest rate which represents default risk associated with a particular counterparty.

(Amounts in thousands, unless otherwise stated)

The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (Dodd-Frank Act) expanded the Commodity Futures Trading Commission's (CFTC) jurisdiction to regulate swaps under the Commodity Exchange Act. The Authority has implemented several compliance measures, including the Authority's Board approved revisions to its commodity and interest rate policies to recognize the obligations and requirements of the Authority under the Dodd-Frank Act. The Authority will continue to evaluate CFTC rules and regulations to determine if there would be any potential impacts to the Authority's risk management strategies and practices.

The Authority's derivative instruments are as follows:

Derivative instrument description		Fair value December 31, 2015	Net change in fair value	Fair value December 31, 2014	Type of hedge	Financial statement classification for changes in fair value
Hedging derivative instruments:						
Financial derivatives:						
Synthetic Fixed-B	$	—	4,179	(4,179)	Cash flow	Deferred outflow
Total Return		1,257	1,257	—	Cash flow	Deferred inflow
Total	$	1,257	5,436	(4,179)		
Commodity derivatives:						
Purchased Power Swaps	$	5,867	(25,307)	31,174	Cash flow	Deferred inflow
Natural Gas Basis Swaps		(2,610)	9,268	(11,878)	Cash flow	Deferred inflow
Total	$	3,257	(16,039)	19,296		
Investment derivative instruments:						
Financial derivatives:						
Synthetic Fixed-A	$	(245,317)	4,581	(249,898)	N/A	Unrealized charges
Basis Swap-A		(7,473)	7,818	(15,291)	N/A	Unrealized charges
Basis Swap-B		(3,736)	3,910	(7,646)	N/A	Unrealized charges
Basis Swap-C		(3,736)	3,910	(7,646)	N/A	Unrealized charges
Total	$	(260,262)	20,219	(280,481)		
Commodity derivatives:						
Power Options	$	(63)	(63)	—	N/A	Unrealized charges
Power - Financial Basis		(3,963)	(3,963)	—	N/A	Unrealized charges
Purchased Power Swaps		(1,149)	(1,149)	—	N/A	Unrealized charges
Natural Gas Options		34,126	182	33,944	N/A	Unrealized charges
Natural Gas Swaps		(149,892)	(20,493)	(129,399)	N/A	Unrealized charges
Total	$	(120,941)	(25,486)	(95,455)		

The terms of the Authority's commodity derivative instruments that were outstanding at December 31, 2015 and 2014 are summarized in the tables below:

	Notional amount (in thousands)	Units	Beginning date	Ending date	Authority pays per unit	Authority receives
2015:						
Natural Gas Swaps	107,930	Dthms	1/1/2016	12/1/2018	$ 2.495 to $ 4.725	Natural Gas at Henry Hub
Natural Gas Basis Swaps	45,548	Dthms	1/1/2016	3/1/2018	$ (1.200) to $ 3.850	Gas Basis between Henry Hub & Transco Z6, NY
Natural Gas Options	43,315	Dthms	1/1/2016	12/1/2018	$ 3.000 to $ 5.550	Natural Gas at Henry Hub
Purchased Power Swaps (1)	5,814	Mwhs	1/1/2016	12/1/2018	$ 29.250 to $ 56.310	Power at PJM West or
Purchased Power Basis	1,010	Mwhs	7/1/2016	12/1/2018	$ (2.100) to $ (1.550)	Power Basis between PJM
Purchased Power Options (2)	168	Mwhs	10/1/2016	11/1/2016	$ 34.000 to $ 34.000	Power at PJM West
2014:						
Natural Gas Swaps	63,515	Dthms	1/1/2015	12/1/2017	$ 3.785 to $ 4.754	Natural Gas at Henry Hub
Natural Gas Basis Swaps	4,692	Dthms	1/1/2015	3/1/2015	$ 0.600 to $ 10.00	Gas Basis between Henry Hub & Transco Z6 NY
Natural Gas Options	82,150	Dthms	1/1/2015	11/1/2017	$ 3.550 to $ 5.55	Natural Gas at Henry Hub
Purchased Power Swaps (1)	7,958	Dthms	1/1/2015	11/1/2017	$ 28.020 to $ 89.49	Power at PJM JCPL
Purchased Power Options (2)	699	Mwhs	5/1/2016	10/1/2017	$ 35.070 to $ 104.36	Power at PJM JCPL

(1) Purchased Power Swaps are executed as either a swap or synthetically, as a combination of a Power Heat Rate swap and a Natural Gas Swap

(2) Purchased Power Options are executed synthetically, as a combination of a Power Heat Rate swap and a Natural Gas Option

The terms of the Authority's interest rate derivative instruments that were outstanding at December 31, 2015 are summarized in the tables below:

Financial derivative	Effective date	Termination date	Authority pays	Authority receives	Original notional	Upfront cash payment
Synthetic Fixed-A	6/1/2003	12/1/2029	5.120%	69.47% of 1-month LIBOR	$ 587,225	106,400
Basis Swap-A	7/1/2004	8/15/2033	SIFMA	70.50% of 1-month LIBOR	502,090	17,500
Basis Swap-B	7/1/2004	8/15/2033	SIFMA	70.50% of 1-month LIBOR	251,045	8,750
Basis Swap-C	7/1/2004	8/15/2033	SIFMA	70.50% of 1-month LIBOR	251,045	8,750
Total Return	6/29/2015	6/29/2020	69.4% 1-month LIBOR+.40%	MMD +1.10%[a]	200,000	—

a Based on lowest long-term rating of the Authority, currently Baa1 .

During 2015, the Authority entered into a five year basis agreement for its direct placement $200 million Electric System General Revenue Bonds Series 2015A Municipal Market Data (MMD) floating rate notes (FRN). Under this agreement, the counterparty pays the Authority an amount equal to the floating MMD FRN coupon, and the Authority pays the counterparty 69.4% of the one month London Interbank Offered Rate (LIBOR) plus 40 basis points. As the coupon payment made by the Authority on the MMD FRNs and its receipts under the basis agreement offset, the Authority's net cost of funds during the five year term of the basis agreement is 69.4% of one month LIBOR plus 40 basis points. At the five year expiration or the early termination of the basis agreement, the counterparty pays the Authority 90% of any increase in the market value of the MMD FRN and the Authority pays the counterparty 100% of any decrease in the market value of the MMD FRN, provided however, that if the Authority exercises its right to call or remarket the MMD FRN, the value of the basis agreement will be zero and neither party will have a payment obligation.

The Authority is exposed to the following risks related to derivative instruments as defined by GASB No. 53:

Termination Risk: Termination risk is the risk that a derivative could be terminated by a counterparty prior to its scheduled maturity due to a contractual event with the Authority owing a termination payment. As long as the Authority fulfills its obligations under the contracts, the counterparties do not have the right to terminate these agreements. The Authority believes that termination risk is low because the counterparties may terminate the agreements only upon the occurrence of specific events such as, payment defaults, other defaults which remain uncured for 30 days after notice, bankruptcy or insolvency of the Authority (or similar events), or a downgrade of the Authority's and its insurers', if any, credit rating below investment grade. If, at the time of termination, the mark-to-market of the derivative was a liability of the Authority, the Authority could be required to pay that amount to the counterparty. Termination risk associated with all of the Authority's derivatives is limited to the fair market value.

Basis Risk: The Authority is exposed to basis risk on certain of its interest rate swaps because the variable-rate payments received by the Authority and those paid either pursuant to the terms of the swap or on the associated variable rate debt may differ. The terms of the interest rate swap transactions are summarized in the charts above.

The Authority is exposed to other basis risk on a portion of its commodity swaps when the commodity swap payment received is based upon a reference price in a market (e.g., natural gas priced at Henry Hub) that differs from the market in which the hedged item is expected to be bought (natural gas priced at New York City gate). If the correlation between these market prices should change substantially, the Authority may incur costs as a result of the hedging derivative instrument's inability to offset the price of the related commodity.

Collateral Posting: Under certain conditions, the Authority may be required to post collateral related to its interest rate derivative instruments. Under the terms of its interest rate derivative agreements, collateral may be required if the Authority's credit ratings and, in the case of insured swaps, the credit ratings of any related interest rate swap insurer, fall below minimum levels as provided in each swap agreement, and the Authority fails to provide alternative credit enhancements. Collateral for its financial derivatives, if required, would approximate fair value. The Authority has never been required to post collateral under its interest rate derivative instruments.

The Authority has collateral requirements with commodity derivative counterparty in the Credit Support Annexes (CSA) of the International Swap Deal Agreements (ISDA). Collateral is required to be posted with the counterparty when the negative fair value of the commodity derivative instrument exceeds the unsecured line of credit established with each counterparty as listed in the counterparty table below. In the event of collateral being posted, the value will equal the difference between the fair value and the amount of the unsecured line of credit. For exchange broker cleared derivative transactions, there is an initial margin requirement on day one of a trade that is calibrated to cover the expected cost of closing out the position in the event of a default. Collateral postings between the exchange clearing broker and the Authority each day thereafter are based on the fair value of the derivative instrument.

Credit Risk: The risk that the counterparty (or its guarantor) will default on its obligations under the agreement. Currently, counterparty risk for the Authority is limited as the termination values of the transactions are generally negative. Additionally, the Authority has sought to limit counterparty risk by contracting only with highly rated counterparties or requiring guarantees of the counterparty's obligations. The Authority has also made use of exchange cleared transactions for a portion of its commodity derivatives. The exchange uses a central clearing counterparty structure along with risk based margin requirements that limits credit risk exposure. Below is a table with the credit-ratings of the Authority's counterparties as of December 31, 2015 (amounts in millions):

(Amounts in thousands, unless otherwise stated)

Counterparty	Moody's	S&P	Counterparty's unsecured line of credit ($M)
Interest rate derivative instruments:			
Bear Stearns Capital Markets, Inc. [1]	A3	A-	—
Citibank, N.A. New York	A1	A	—
Merrill Lynch Capital Services, Inc. [2]	Baa1	BBB+	—
UBS AG, Stamford Branch	A2	A	—
Wells Fargo Bank, N.A.	Aa2	AA-	—

1 Ratings reflect the rating of its parent company, JP Morgan Chase & Co.
2 Ratings reflect the rating of Bank of America Corp.

Counterparty	Moody's	S&P	Counterparty's unsecured line of credit ($M)
Commodity derivative instruments:			
Barclays Bank PLC	A2	A-	$25
BP Energy Company	Baa1	A	$10
Cargill, Incorporated	A2	A	$15
Citigroup Energy, Inc.	Baa1	BBB+	$10
J. Aron & Company	A3	BBB+	$40
JPMorgan Chase Bank, N.A.	Aa2	A+	$35
Macquarie Energy LLC	A2	A	$10
Merrill Lynch Commodities, Inc.	Baa1	BBB+	$10
Morgan Stanley Capital Group Inc.	A3	BBB+	$40
Next Era Power Marketing	Baa1	A-	$10
Societe Generale	A2	A	$25
Bank of Nova Scotia	Aa2	A+	$25

(8) Utility Plant and Property and Equipment

Additions to and replacements of utility plant are capitalized at original cost, which includes material, labor, indirect costs associated with an addition or replacement, plus an allowance for borrowed funds used during construction. The cost of renewals and betterments relating to units of property is added to utility plant. The cost of property replaced, retired, or otherwise disposed of is deducted from utility plant and, generally, together with dismantling costs less any salvage, is charged to accumulated depreciation. The cost of repairs and minor renewals is charged to maintenance expense. Mass properties (such as poles, meters, and wire) are accounted for on an average unit cost basis by year of installation.

(Amounts in thousands, unless otherwise stated)

The following schedule summarizes the utility plant and property and equipment of the Authority as of December 31, 2015:

		Beginning Balances	Increases	Decreases	Ending Balances
Utility plant	$	6,342,423	456,942	(8,250)	6,791,115
Office equipment, furniture, and leasehold improvements		18,409	—	(729)	17,680
Long lived assets- asset retirement cost		15,542	—	—	15,542
Accumulated depreciation		(2,588,307)	(129,086)	766,343	(1,951,050)
Total utility plant - net		3,788,067	327,856	757,364	4,873,287
Generation and transmission assets under capital lease		3,751,349	—	—	3,751,349
Accumulated depreciation		(1,193,103)	(178,997)	—	(1,372,100)
Total assets under capital lease - net		2,558,246	(178,997)	—	2,379,249
Construction work in progress		359,381	358,221	(431,985)	285,617
Retirement work in progress		21,363	27,417	(38,770)	10,010
		380,744	385,638	(470,755)	295,627
Totals	**$**	**6,727,057**	**534,497**	**286,609**	**7,548,163**

(Amounts in thousands, unless otherwise stated)

The following schedule summarizes the utility plant and property and equipment of the Authority as of December 31, 2014:

		Beginning Balances	Increases	Decreases	Ending Balances
Utility plant	$	6,019,817	425,593	(102,987)	6,342,423
Office equipment, furniture, and leasehold improvements		17,684	738	(13)	18,409
Long lived assets- asset retirement cost		15,542	—	—	15,542
Accumulated depreciation		(2,520,685)	(116,522)	48,900	(2,588,307)
Total utility plant - net		3,532,358	309,809	(54,100)	3,788,067
Generation and transmission assets under capital lease		3,751,349	—	—	3,751,349
Accumulated depreciation		(1,025,260)	(167,843)	—	(1,193,103)
Total assets under capital lease - net		2,726,089	(167,843)	—	2,558,246
Construction work in progress		385,183	429,789	(455,591)	359,381
Retirement work in progress		39,396	13,504	(31,537)	21,363
		424,579	443,293	(487,128)	380,744
Totals	**$**	**6,683,026**	**585,259**	**(541,228)**	**6,727,057**

(9) Nine Mile Point Nuclear Power Station, Unit 2

The Authority has an 18% undivided interest in NMP2 in Oswego County, New York. The other 82% interest is owned by Constellation Energy Nuclear Group, LLC (CENG), a joint venture of Exelon Corporation and EDF, a large electric-power company headquartered in France. The unit is operated by Exelon.

NMP2 has a maximum net capacity of 1,293 MW, and it operated at an average net power of 1,261 MW in 2015. The Authority is entitled to 18% of the unit's capacity and energy, and is obligated to pay 18% of its operating and maintenance costs, nuclear-fuel costs, and costs of capital additions. The Authority's net utility-plant investment in NMP2, excluding nuclear fuel, was $374 million and $353 million as of December 31, 2015 and 2014, respectively. Nuclear-fuel costs are amortized monthly and distributed over its share of the electric energy generated by the unit.

An operating agreement between Exelon and the Authority provides for a management committee comprised of one representative from each co-tenant, with the co-tenants having joint approval rights for the annual business plan, the annual budget, and material changes to the budget. However, as the operator, Exelon has ultimate authority for all operating and maintenance decisions.

On October 31, 2006, the Nuclear Regulatory Commission granted a 20-year extension to the operating license for NMP2, which now expires on October 31, 2046.

(a) Nuclear Plant Decommissioning

The estimate of the decommissioning-cost obligation for NMP2 is based on a site-specific decommissioning study performed in 2014 with updates performed by Exelon in 2015. As of December 31, 2015 and 2014, the Authority's share of the estimated costs for both the contaminated and non-contaminated portions of the unit was \$57 million and \$58 million, respectively, and is included in the Statements of Net Position as a component of the ARO. The Authority maintains a nuclear-decommissioning trust fund (NDT) for its share of the decommissioning costs. As of December 31, 2015 and 2014, respectively, it had an approximate value of \$110 million and \$111 million. Based on deposits and assumed investment returns of these funds, the Authority believes that their value will be sufficient to meet its decommissioning obligations.

(b) Radioactive Waste

CENG contracted with the Department of Energy (DOE) for permanent disposal of high level radioactive waste (spent fuel) from NMP2. A permanent nuclear-waste repository was supposed to be operational by January 31, 1998. However, plans for the repository at Yucca Mountain in Nevada were ultimately abandoned, and the DOE has not indicated where or when an alternate site will be in operation. Consequently, an independent spent fuel storage installation (ISFSI) was constructed at the Nine Mile Point site in 2013 to store spent fuel from both Units 1 and 2 until such time as a permanent DOE repository is open. The costs of this facility are being reimbursed by DOE from funds paid to it for final fuel disposal by nuclear-plant licensees. The requirement for continuation of these payments was suspended after the Yucca Mountain Project was cancelled.

(c) Liability for Nuclear Accidents

The federal Price-Anderson Act limits the liability of reactor licensees for public claims resulting from any single nuclear accident. This limit currently stands at \$13.6 billion. To cover this liability, the Act requires all licensees to participate in a two-tier insurance system. Under the first tier, each licensee is required to carry the maximum limit of primary insurance available from private sources. This limit currently stands at \$375 million. Exelon maintains this coverage, and the Authority reimburses a share of its cost. Inasmuch as the coverage involves both Units 1 and 2, the Authority's share of costs is not necessarily 18%.

To provide the second tier of coverage, all licensees are required to participate in a program under which all participants will be charged a retrospective premium to cover injuries and damage in excess of the limit of a licensee's primary insurance. This premium is currently limited to \$127 million per reactor per incident. With 104 reactors participating, this tier provides \$13.2 billion of surety. The

Authority's maximum potential retroactive assessment is $22.9 million, payable at $3.4 million annually.

In addition to the coverages described above, the Authority maintains its own insurance for replacement-power expenses incurred during prolonged [accidental] outages. Under this program, coverage would commence twelve weeks after any covered [accidental] outage, with reimbursement at the rate of approximately $630,000 per week for the first 52 weeks, reduced to $504,000 per week for an additional 110 weeks for the purchase of replacement power, with a maximum limit of $88.2 million.

(d) Other

On March 12, 2012, the NRC issued three safety-enhancement orders to NMP2 as a result of lessons learned from the 2011 disaster at the Fukushima Daiichi facility in Japan. One of those orders, has been complied with and the remaining plant modifications will be completed during the 2016 refueling outage, which is scheduled to begin in April 2016.

(10) Cash, Cash Equivalents and Investments

The majority of the Authority's cash and equivalent investments are managed by an external investment manager. The Authority's investments primarily consist of five accounts: the Operating Fund, the Rate Stabilization Fund, the Grant Proceeds Fund and the Construction Fund. The Operating Fund is managed to meet the liquidity needs of the Authority, the Rate Stabilization Fund is managed to maximize the return on investment, the Grant Proceeds Fund holds proceeds from FEMA designated for future storm mitigation projects, and the Construction Fund is used to fund capital expenditures from the proceeds of bonds. In accordance with its agreements with banks issuing letters of credit to secure the Authority's bonds, the Authority has agreed that the amount held in the Rate Stabilization Fund will not be less than $150 million.

The Authority's investment policy places limits on investments by issuer and by security type and addresses various risks described below. The Board may also specifically authorize, as it deems appropriate, other investments that are consistent with the Authority's investment objective. The Authority regularly reviews its investment policy to ensure continued effectiveness.

(a) Risks

Credit Risk: The Authority's permissible investments and related minimum credit ratings include U.S. Treasury and Federal Agency obligations (AA- or Aa3), repurchase agreements (A-1 or P-1), commercial paper (A-1 or P-1), corporate notes and master notes (A- or A3), asset backed securities (AAA), certificates of deposit (A- or A3), money-market mutual funds (AAAm), investment contracts (AA- or Aa3), municipal obligations (A- or A3), and variable rate notes (based on the specific asset type noted above). The Authority's investment policy prohibits investments involving complex derivatives, reverse repurchase agreements, auction rate securities, home equity asset backed securities, short selling and arbitrage related investment activity.

Concentration of Credit Risk: To address concentration of credit risk, the Authority's investment policies have established limits such that no more than 5% of the investment portfolio may be invested in the securities of any one issuer except as follows: (i) U.S. Treasury Obligations up to 100%; (ii) each Federal agency up to 20%; (iii) repurchase agreements up to 10% or $50 million; and, (iv) money-market mutual funds up to 75% maximum.

Custodial Credit Risk: The Authority believes that custodial credit risk related to its investments is minimal, as it is the Authority's policy and practice, as stipulated in its Investment Guidelines, that investments be held by a third-party custodian who may not otherwise be a counter-party to the transactions, and that all securities are free and clear of any lien and held in a separate account, in the name of the Authority.

Custodial credit risk for cash deposits (including demand deposits, time deposits and certificates of deposit issued by a commercial bank) is the risk that in the event of a bank failure, the Authority's deposits may not be returned, either in part or in whole. The Authority's policy to address this risk requires that all demand deposits, time deposits and certificates of deposits issued by a commercial bank not having a long-term credit rating of A3 or higher by Moody's, or A- or higher by Standard and Poor's, be fully collateralized above the Federal Deposit Insurance Corporation coverage. Commercial banks with long-term credit ratings at or above A3/A- do not require collateralization unless otherwise required by the Authority's Chief Financial Officer.

As of December 31, 2015 and 2014, the Authority had deposits of $239 million and $180 million, respectively, which are included in both restricted and unrestricted cash.

Interest Rate Risk: The Authority's investment policy states that investments generally have maturities of 12 months or less. Investment maturities may exceed 12 months provided that the maturity does not exceed the expected disbursement date of those funds, the total average portfolio maturity is one year or less and no individual maturity exceeds three years, with the exception of U.S. government obligations and investment contracts. As of December 31, 2015 and 2014, all of the Authority's investments had maturities of less than 12 months.

(Amounts in thousands, unless otherwise stated)

(b) Unrestricted cash, cash equivalents and investments

As of December 31, 2015 and 2014, the Authority had the following cash, cash equivalents and investments:

Deposit/investment type		2015 Fair value	Percent of portfolio		Cash and cash equivalents	Investments
Short-term discount notes:						
Commercial paper	$	157,211	24%	$	157,211	—
Federal agencies		29,551	4%		29,551	—
Money-market funds		403,461	66%		403,461	—
Cash and collateralized deposits		10,475	2%		10,475	—
Mutual Fund Investments		29,500	4%		—	29,500
Total	$	630,198	100%	$	600,698	29,500

Deposit/investment type		2014 Fair value	Percent of portfolio		Cash and cash equivalents	Investments
Short-term discount notes:						
Commercial paper	$	91,646	12%	$	91,646	—
Federal agencies		9,041	1%		9,041	—
Treasury bills		84,649	11%		84,649	—
Money-market funds		565,142	72%		565,142	—
Cash and collateralized deposits		31,988	4%		31,988	—
Total	$	782,466	100%	$	782,466	—

Included in amounts above are deposits made to the OPEB Account. To meet the Authority's obligation for certain future PSEG Long Island employee post-employment health and life insurance benefit plan expenses that are pass-through expenditures payable by the Authority (during the term of the A&R OSA and at the termination of the agreement), the Authority has funded an OPEB Account and invested such funds as permitted by the Authority's investment guidelines, which are similar to investments commonly made in accounts dedicated to prefunding OPEB obligations. The Authority also incurs similar liabilities for the post-employment health and life insurance benefits for its own employees. As of December 31, 2015, the Authority has approximately $30 million held in investments and approximately $21.7 million held in cash and cash equivalents. Approximately $48.4 million is related to the PSEG Long Island employee benefit obligation and $3.3 million is related to the Authority employee benefit obligation.

In the event that the Authority's Chief Executive Officer (CEO) or Chief Financial Officer (CFO) determine there are insufficient revenues to pay reasonable and necessary operating expenses or to make payments on bonds or parity obligations, the CEO or CFO is authorized after notifying the Finance and Audit Committee of the Board to release funds from the OPEB Account for such purposes. As such, the OPEB Account is not restricted and is included in the tables above.

(c) Restricted cash and cash equivalents

Restricted Cash for Working Capital Requirements

In accordance with the A&R OSA, the Authority is required to advance fund an operating account available to PSEG Long Island to pay for operating and capital expenditures that PSEG Long Island incurs as the Authority's agent in the management of the Authority's T&D system. The Authority is required to maintain in this account three months of anticipated T&D operating and capital costs plus separate storm and tax funding accounts. These accounts totaled $208 million and $148 million, as of December 31, 2015 and 2014, respectively, and were held in a collateralized deposit account. These funds are determined to be restricted due to the contractual obligation of the Authority to pre-fund the account but are considered part of the Authority's working capital.

FEMA Grant Proceeds

The Authority received from FEMA approximately $502 million for storm hardening work as well as initial repair costs for certain Authority assets. These amounts exceed the expenditures of the Authority for such projects to date, and the Authority has segregated those funds for future use as required by the FEMA grant agreement.

UDSA

Restructuring charges are held by the bond Trustee in the Collection Account to satisfy debt service on the Restructuring Bonds. The Collection Account for the bonds consists of four subaccounts: a General Subaccount, an Excess Funds Subaccount, a Reserve Subaccount, and an Upfront Financing Costs Subaccount. The Collection Account (other than the Upfront Financing Costs Subaccount) secures the Restructuring Bonds. For administrative purposes, the subaccounts may be established by the Trustee as separate accounts which will be recognized individually as subaccounts and collectively as the Collection Account.

Restricted cash held by the Trustee, as of December 31, 2015, includes $3 million in the General Subaccounts, and $30.3 million in the Reserve Subaccounts and Upfront Financing Costs Subaccounts.

The UDSA has a separate set of investment guidelines that are specifically designed to address its legal and contractual requirements. These guidelines mandate that such investments be matched to meet the obligations of the bond and interest payments.

(Amounts in thousands, unless otherwise stated)

As of December 31, 2015 and 2014, the Authority had the following in restricted cash and cash equivalent balances:

Deposit/investment type	2015 Fair value	Percent of portfolio	Cash and cash equivalents	Investments
Short-term discount notes:				
Commercial paper	$ 127,118	18%	$ 127,118	—
Federal agencies	33,536	5%	33,536	—
Money-market funds	354,718	46%	354,718	—
Cash and collateralized deposits	228,235	32%	228,235	—
Total	$ 743,607	100%	$ 743,607	—

Deposit/investment type	2014 Fair value	Percent of portfolio	Cash and cash equivalents	Investments
Short-term discount notes:				
Commercial paper	$ 63,200	10%	$ 63,200	—
Federal agencies	22,718	4%	22,718	—
Treasury bills	48,369	8%	48,369	—
Money-market funds	335,810	54%	335,810	—
Cash and collateralized deposits	148,287	24%	148,287	—
Total	$ 618,384	100%	$ 618,384	—

(d) *Nuclear Decommissioning Trusts (NDT)*

The Authority maintains a separate investment policy applicable to the long-term investments in the NDT which is held to meet the Authority's obligation with respect to the eventual decommission of the Authority's 18% interest in the NMP2 nuclear facility. The NDT guidelines detail permissible investments and portfolio restrictions. This investment policy is reviewed regularly to ensure that the value in the trusts in 2046 (the year in which decommissioning activities are scheduled to begin), will be sufficient to meet decommissioning obligations.

Credit Risk: The guidelines attempt to minimize risk by limiting permissible investments to include: obligations of the U.S. government and its agencies; corporate or other obligations with an BBB-/Baa3 or better rating; mortgage obligations rated AA/Aa or higher; commercial paper with a rating of A-1 or P-1; certificates of deposit; Yankee certificates of deposit and bankers acceptances of domestic banks with A-/A3 rating or better, short-term money market investment accounts that conform to the aforementioned permissible investments; and with respect to the long-term NDT investment portfolio only, equity investments limited to portfolio funds of securities designed to replicate the overall market measured by benchmark market indices such as the S&P 500 Index. Within the NDT investment portfolio, the use of equity investments in an S&P 500 index mutual fund is a permissible investment and is limited to a target exposure of 35% with a quarterly rebalancing within plus or minus 5%. The fixed income portion of the NDT investment portfolio must maintain an average credit rating of A or better with no more than 30% of the portfolio invested in notes and bonds rated in the BBB and A categories and no more than 20% of the portfolio invested in municipal securities.

(Amounts in thousands, unless otherwise stated)

Concentration of Credit Risk: To address this risk, the investment policies have established limits such that no more than 5% of the portfolio may be invested in the securities of any one issuer with the exception of U.S. government and its agencies securities. In addition, no more than 25% of the portfolio may be invested in securities of issuers in the same industry.

Custodial Credit Risk: The NDT does not have a policy relative to custodial credit risk of its deposits, however, as a practical matter, it defers to the policies of the Authority.

Interest Rate Risk: Due to the long-term nature of the NDT asset, interest rate risk is managed to track the Barclays Capital U.S. Float Adjusted Aggregate Bond Market Index. The portfolio's duration is required to fall within a range of 20% below the duration of the index and 10% above the duration of the index.

As of December 31, 2015 and 2014, the NDT had the following investments:

Investment type		2015 Fair value	Percent of portfolio
U.S. government and its agencies obligations	$	48,847	44%
Corporate Notes/Bonds		20,724	19%
Commingled equity fund		40,865	37%
Total	$	110,436	100%

Investment type		2014 Fair value	Percent of portfolio
U.S. government and its agencies obligations	$	48,254	44%
Corporate Notes/Bonds		21,835	20%
Commingled equity fund		40,580	36%
Total	$	110,669	100%

(Amounts in thousands, unless otherwise stated)

The overall duration of the three individual accounts averaged 5.7 years and 5.9 years at December 31, 2015 and 2014, respectively.

(11) Long-Term and Short-Term Debt

(a) Electric System General Revenue Bonds and Subordinated Revenue Bonds

The Authority financed the cost of acquiring the T&D system from LILCO with Electric System General Revenue Bonds and Electric System Subordinated Revenue Bonds (collectively, the Bonds). Ongoing capital improvements are funded through the issuance of debt, except where grants or excess cash flow provide the ability to cash fund such expenditures. LIPA and the Authority entered into a Financing Agreement, whereby LIPA transferred to the Authority all of its right, title and interest in and to the revenues generated from the operation of the T&D system, including the right to collect and receive the same.

All of the Authority’s bonds are secured by a Trust Estate as pledged under the Authority’s Bond Resolution (the Resolution). The Trust Estate consists principally of the revenues generated by the operation of the T&D system and has been pledged to the Authority.

Below are the bond transactions completed during the year ended December 31, 2015:

Revenue Obligations:	2015A-1, A-2 General Revenue Bonds	Par Amount:	$ 200,000
Purpose:	Re-finance Series 2012D variable-rate bonds plus a portion of Series 2001-1A & Series 2001-2B due to expiring bank facilities	Date Closed:	June 16, 2015
Comments:	Direct placement Floating Rate Notes	Deferred Loss:	$ 151
Revenue Obligations:	2015B General Revenue Bonds	Par Amount:	$ 117,230
Purpose:	Fund system improvements & pay issuance costs	Date Closed:	November 18, 2015
Comments:	New money fixed rate issue		
Revenue Obligations:	2015C General Revenue Bonds	Par Amount:	$ 149,000
Purpose:	To re-finance the remaining balance of the Series 2001-1A and 2B variable-rate bonds due to expiring bank facilities	Date Closed:	November 18, 2015
Comments:	LIBOR Floating Rate Notes		
Revenue Obligations:	2015A General Revenue Notes	Par Amount:	$ 325,000
Purpose:	Supplement liquidity after downsizing revolver	Date Closed:	March 30, 2015
Comments:	$50 million outstanding as of December 31, 2015		

(Amounts in thousands, unless otherwise stated)

Below are the bond transactions completed during the year ended December 31, 2014:

Revenue Obligations:	2014A General Revenue Bonds	Par Amount: $	413,070
Purpose:	Fund system improvements & refund the remaining balance of the 2004A bonds & pay issuance costs	Date Closed:	December 4, 2014
Comments:	Refunding and new money		
Revenue Obligations:	2014B General Revenue Bonds	Par Amount: $	164,950
Purpose:	Fund system improvements & pay issuance costs	Date Closed:	December 4, 2014
Comments:	Federally taxable new money fixed rate debt		
Revenue Obligations:	2014C General Revenue Bonds	Par Amount: $	150,000
Purpose:	Refund $50 million Series 2001-1B & $100 million Series 2001-3A	Date Closed:	December 4, 2014
Comments:	LIBOR Floating Rate Notes		
Revenue Obligations:	Subordinated Revenue Commercial Paper Notes	Par Amount: $	215,000
Purpose:	Fund various system improvements, supplement liquidity & refund existing commercial paper	Date Closed:	December 22, 2014
Comments:	$0 outstanding as of December 31, 2014		

(b) UDSA

The Authority's Board adopted the Financing Orders authorizing the issuance of Restructuring Bonds by the UDSA to allow the Authority to retire a portion of its outstanding indebtedness and provide savings to the Authority's customers as measured on a net present value basis. The Restructuring Bonds are not obligations of the Authority, PSEG Long Island or any of their affiliates; however, the UDSA is a component unit of the Authority and consolidated into these financial statements.

Below is the UDSA bond transaction completed during the year ended December 31, 2015. The UDSA had no bond market transactions during 2014.

Revenue Obligations:	2015 Restructuring Bonds	**Par Amount:** $	1,002,115
Purpose:	Retire certain higher cost Authority bonds	**Date Closed:**	October 16, 2015
		NPV Savings:	127,978
Comments:	Issued by UDSA	**Deferred Loss:**	116,516

(Amounts in thousands, unless otherwise stated)

The Authority's short-term and long-term debt at December 31, 2015 consisted of the following:

	Beginning balance	Accretion/ additions	Maturities	Refundings	Ending balance	Years of Maturity	Interest Rate	
							(%)	
General revenue bonds/notes:								
Series 1998A	$ 113,622	6,089	—	—	119,711	2016-2028	5.05-5.30	(a)
Series 2000A	361,014	20,330	33,065	—	348,279	2016-2029	5.54-5.95	(a)
Series 2003C	36,645	—	—	—	36,645	2029	5.25	(b)
Series 2006A	564,125	—	—	64,925	499,200	2016-2026	4.00-5.25	(b)
Series 2006B	95,655	—	—	95,655	—	2035	NA	(b)
Series 2006C	194,105	—	—	194,105	—	2035	NA	(b)
Series 2006D	195,870	—	110,715	29,795	55,360	2016-2025	4.11-5.00	(b)
Series 2006E	391,085	—	—	80,845	310,240	2017-2022	4.00-5.00	(b)
Series 2006F	271,005	—	20,115	11,840	239,050	2016-2033	4.00-5.00	(b)
Series 2008A	598,720	—	—	352,410	246,310	2030-2033	5.50-6.00	
Series 2008B	146,725	—	—	95,725	51,000	2019-2033	5.25-5.75	
Series 2009A	331,220	—	—	108,610	222,610	2016-2033	3.50-6.25	
Series 2010B	210,000	—	—	—	210,000	2020-2041	4.85-5.85	(c)
Series 2011A	245,590	—	—	11,365	234,225	2016-2038	4.00-5.00	(b)
Series 2012A	250,000	—	—	—	250,000	2037-2042	5.00	(b)
Series 2012B	189,325	—	610	—	188,715	2016-2029	3.00-5.00	
Series 2012C	175,000	—	—	—	175,000	2033	0.01	(b)(d)
Series 2012D	149,000	—	—	149,000	—	2033	NA	(b)(d)
* Series 2013A	65,000	—	—	65,000	—	2016	NA	(d)
Series 2014A	413,070	—	—	—	413,070	2034-2044	4.00-5.00	
Series 2014B	164,950	—	—	—	164,950	2018-2026	2.36-4.13	
Series 2014C FRN	150,000	—	—	—	150,000	2033	0.82	(b)(d)
Series 2015A1	—	51,000	—	—	51,000	2033	3.80-4.09	(b)(d)
Series 2015A2	—	149,000	—	—	149,000	2029	3.49-3.86	(b)(d)
Series 2015B	—	117,230	—	—	117,230	2019-2045	3.00-5.00	
Series 2015C	—	149,000	—	—	149,000	2033	1.051	(b)(d)
* Series 2015GR1-3CP	—	50,000	—	—	50,000	2016	0.20-0.33	(d)
Subtotal	5,311,726	542,649	164,505	1,259,275	4,430,595			
Subordinate revenue bonds/notes:								
Series 1-3	350,000	—	—	350,000	—	2033	NA	(b)(d)
* Series 2000 CP 1-3	215,000	—	—	215,000	—	2015	NA	(d)
* Series 2014 CP 1AB	—	200,000	—	—	200,000	2017	0.15-0.30	(d)
* Series 2014 CP 2AB	—	100,000	—	—	100,000	2017	0.21-0.44	(d)
Subtotal	565,000	300,000	—	565,000	300,000			
UDSA restructuring bonds:								
Series 2013T	482,934	—	—	—	482,934	2017-2023	2.04-3.44	
Series 2013TE	1,449,390	—	15,000	—	1,434,390	2016-2039	5.00	
Series 2015TE	—	1,002,115	—	—	1,002,115	2021-2035	3.00-5.00	
Subtotal	1,932,324	1,002,115	15,000	—	2,919,439			
	7,809,050	1,844,764	179,505	1,824,275	7,650,034			
Plus: Net premium	202,346	190,919	22,536	—	370,729			
* Less: Short term debt	(280,000)				(350,000)			
Less: Current maturities	(179,505)				(238,295)			
Total long term debt	$ 7,551,891				7,432,468			

a Capital Appreciation Bonds
b Certain bonds of this series are subject to interest rate exchange agreements
c Taxable Build America Bonds subject to federal subsidy, rate shown is pre-subsidy level
d Variable rate (rate presented as of the fourth quarter of 2015)
* Short term debt

(Amounts in thousands, unless otherwise stated)

The Authority's short-term and long-term debt at December 31, 2014 consisted of the following:

	Beginning balance	Accretion/ additions	Maturities	Refundings	Ending balance	Years of Maturity	Interest Rate (%)	
General revenue bonds/notes:								
Series 1998A	$ 107,842	5,780	—	—	113,622	2015-2028	5.05-5.30	(a)
Series 2000A	372,651	20,968	32,605	—	361,014	2015-2029	5.54-5.95	(a)
Series 2003B	28,690	—	28,690	—	—	2014	5.25	
Series 2003C	36,645	—	—	—	36,645	2029	5.25	(b)
Series 2004A	22,270	—	—	22,270	—	2029-2034	5.00-5.10	(b)
Series 2006A	564,125	—	—	—	564,125	2016-2026	4.00-5.25	(b)
Series 2006B	95,655	—	—	—	95,655	2035	4.50-5.00	(b)
Series 2006C	194,105	—	—	—	194,105	2035	5.00	(b)
Series 2006D	211,785	—	15,915	—	195,870	2015-2025	4.11-5.00	(b)
Series 2006E	391,085	—	—	—	391,085	2017-2022	4.00-5.00	(b)
Series 2006F	271,005	—	—	—	271,005	2015-2033	4.00-5.00	(b)
Series 2008A	598,720	—	—	—	598,720	2030-2033	5.50-6.00	
Series 2008B	146,725	—	—	—	146,725	2019-2033	5.25-5.75	
Series 2009A	331,220	—	—	—	331,220	2016-2033	3.50-6.25	
Series 2010B	210,000	—	—	—	210,000	2020-2041	4.85-5.85	(c)
Series 2011A	245,590	—	—	—	245,590	2016-2038	4.00-5.00	
Series 2012A	250,000	—	—	—	250,000	2037-2042	5.00	
Series 2012B	192,135	—	2,810	—	189,325	2014-2029	3.00-5.00	(b)
Series 2012C	175,000	—	—	—	175,000	2033	0.02-.0.05	(b)(d)
Series 2012D	149,000	—	—	—	149,000	2033	0.01-0.05	(d)
* Series 2013A	263,000	337,000		535,000	65,000	2016	1.01-3.25	
Series 2014A	—	413,070	—	—	413,070	2034-2044	4.00-5.00	
Series 2014B	—	164,950	—	—	164,950	2018-2026	2.36-4.13	
Series 2014C FRN	—	150,000	—	—	150,000	2033	1.10	(b)(d)
Subtotal	4,857,248	1,091,768	80,020	557,270	5,311,726			
Subordinate revenue bonds/notes:								
Series 1-3	350,000	—	—	—	350,000	2033	0.02-0.11	(b)(d)
* Series 2000 CP 1-3	—	215,000	—	—	215,000	2015	0.12-.018	(b)(d)
Subtotal	350,000	215,000	—	—	565,000			
UDSA restructuring bonds:								
Series 2013T	482,934	—	—	—	482,934	2017-2023	2.04-3.44	
Series 2013TE	1,539,390	—	90,000	—	1,449,390	2015-2039	5.00	
Subtotal	2,022,324	—	90,000	—	1,932,324			
	7,229,572	1,306,768	170,020	557,270	7,809,050			
Plus: Net premium	188,083	37,291	23,028	—	202,346			
* Less: Short term debt	(263,000)				(280,000)			
Less: Current maturities	(170,020)				(179,505)			
Total long term debt	$ 6,984,635				7,551,891			

a Capital Appreciation Bonds
b Certain bonds of this series are subject to interest rate exchange agreements
c Taxable Build America Bonds subject to federal subsidy, rate shown is pre-subsidy level
d Variable rate (rate presented as of the fourth quarter of 2014)
* Short term debt

(Amounts in thousands, unless otherwise stated)

The debt service requirements for the Authority's consolidated bonds outstanding (excluding short-term debt such as general revenue notes, commercial paper notes, and revolving credit facility but including the UDSA Restructuring Bonds) as of December 31, 2015 are as follows:

Due		Principal*	Interest	Net swap payments	Total
2016	$	238,295	310,070	23,606	571,971
2017		194,648	302,231	18,321	515,200
2018		212,783	298,553	15,385	526,721
2019		267,281	291,034	15,385	573,700
2020		272,532	284,036	15,385	571,953
2021–2025		1,514,515	1,269,687	76,926	2,861,128
2026–2030		1,716,070	947,597	46,705	2,710,372
2031–2035		1,599,930	553,108	—	2,153,038
2036–2040		1,128,675	241,464	—	1,370,139
2041–2045		369,410	35,708	—	405,118
Total	$	7,514,139	4,533,488	211,713	12,259,340

*Future interest on Capital Appreciation Bonds are included in principal maturities.

Future debt service on the variable rate bonds and floating rate portion of any floating-to-fixed rate swaps use an assumed rate of 1.10% for 2016, 2.00% and 2.50% for 2017 and thereafter, respectively. For bonds subject to floating-to-fixed rate swap agreements, the "net swap payments" represent the fixed swap rate payment net of the assumed future variable rate swap receipts for each agreement.

(c) Interest Rate Swap Agreements

The Authority has entered into several interest rate swap agreements with various counterparties to modify the interest rate on outstanding debt. For a further discussion, see note 7.

(d) Short-Term Debt

General Revenue Notes - Revolving Credit Agreement

In 2013, the Authority secured a three-year senior lien revolving credit agreement, Series 2013A, that allowed for borrowing for up to $500 million. During 2015, the Authority amended this agreement reducing extending the term by one year to March 2017 and reducing the facility to $337.5 million, of which none was outstanding at December 31, 2015. As of December 31, 2014, the Authority had $65 million outstanding.

General Revenue Notes - Commercial Paper

In 2015, the Authority issued Electric System General Revenue Notes, Series GR-1, GR-2 and GR-3, each in two sub series: A Taxable; and B Tax-Exempt. The GR-1 Notes shall not exceed $200 million outstanding at any time. The GR-2 Notes shall not exceed $75 million outstanding at any time. The

GR-3 Notes shall not exceed $50 million outstanding at any time. At December 31, 2015, the Authority had $50 million GR-1A notes outstanding under this program. The Letter of Credit supporting the GR-1 Notes expires in June 2020 while the Letters of Credit supporting the GR-2 and GR-3 Notes expire in March 2018.

Subordinated Revenue Notes - Commercial Paper
In December 2014, the Authority established the Series 2014 Commercial Paper (CP) Notes, CP-1 and CP-2, in two subseries, A taxable and B tax-exempt. Series 2014 CP-1 Notes shall not exceed $200 million outstanding at any time. Series 2014 CP-2 Notes shall not exceed $100 million outstanding at any time.

As of December 31, 2015, $300 million of the Authority's 2014 CP Notes, Series CP-l and CP-2, were outstanding and are included in short term debt on the Statements of Net Position. As of December 31, 2014, no 2014 CP Notes were outstanding. In connection with the issuance of the Series 2014 CP Notes, the Authority has entered into Letter of Credit agreements. The Letters of Credit supporting the Series 2014 CP-1 and CP-2 Notes are scheduled to expire in December 2017.

The Series 2014 CP Notes replaced a prior commercial paper program consisting of Series CP-1, CP-2 and CP-3 with a not to exceed $300 million authorization upon the expiration of the Letter of Credit agreements supporting that prior program on January 27, 2015. As a result, in January 2015, the Authority redeemed all of its outstanding Notes under the prior program, Series CP-1 through CP-3, with funds from its 2014 CP Notes program.

(e) Fixed obligation coverage ratio

Effective January 1, 2016, the Authority adopted the "public power model" of rate-setting which makes use of the debt service coverage method in determining revenue requirements. The Authority's methodology for calculating the fixed obligation coverage ratio excludes certain specified non-cash items from expenses. Depreciation expense, amortization of the Acquisition Adjustment and other regulatory assets, as well as the difference between accrual expense and actual cash required cash contributions to PSEG Long Island pension and OPEBs are non-cash expenses excluded from the coverage calculation. Also, adjusted in the revenue section of this calculation are the revenues received from certain customers that are used to satisfy the regulatory asset that were established when the Authority issued debt to fund such projects. For calculating the coverage ratios, these cash receipts are available to meet the Authority's fixed obligation requirements, although such receipts are excluded from revenues for accrual accounting purposes.

Certain interest related costs such as interest rate derivative costs, letters of credit and remarketing fees, bond administration costs, and interest related to customer deposits are not required to have coverage and are therefore, deducted as an ordinary expense from operating income. Included for coverage are the Authority and the UDSA principal and interest payments, including interest payments on the Authority's commercial paper program and short-term debt.

(Amounts in thousands, unless otherwise stated)

The Authority applied this method to the year ended December 31, 2015 and 2014 results for information purposes as shown below:

Years ended December 31,		**2015**	**2014**
Operating revenues	$	3,505,209	3,613,982
Other income		92,073	152,378
Receipts related to regulatory assets		11,969	12,540
Total revenues and income		3,609,251	3,778,900
Operating expenses		(3,187,383)	(3,351,379)
Add non cash expenses/(deduct cash funding)			
Depreciation and amortizations		235,010	226,966
Capital lease allowance		310,882	309,011
PSEG Long Island retirement benefit accrual expense[1]		-	-
PSEG Long Island retirement benefit funding[1]		-	-
Other interest expense		(43,900)	(46,709)
Total expenses		(2,685,391)	(2,862,111)
Funds available for debt service	**$**	**923,860**	**916,789**
Principal and interest - Authority		378,783	298,791
Principal and interest - UDSA		101,286	180,029
Capital lease obligation		310,882	309,011
Total fixed obligation debt service	**$**	**790,951**	**787,831**
Fixed Obligation Coverage Ratio:			
Excluding UDSA		1.19	1.21
Including UDSA		1.17	1.16

[1] The public power model as adopted by the Authority's Board in 2015 for 2016 and beyond, adds back the retirement benefits accrual expense and deducts the cash funding of the pension benefits related to operating expense. OPEB contributions are not deducted, as they are funded through coverage, consistent with the DPS recommendation. For 2014 and 2015, which are prior to the rate case methodology, these adjustments are not reflected in the calculation.

(Amounts in thousands, unless otherwise stated)

(f) ***Changes in noncurrent liabilities***

The Authority's other long term liabilities as of December 31, 2015 are comprised of the following:

		Beginning Balance	Increases	Decreases	Ending Balance
Other long-term liabilities:					
Long term liabilities and unrealized credits	$	97,291	—	(3,761)	93,530
Borrowings		91,779	—	(4,715)	87,064
Claims and damages		20,935	8,547	(1,660)	27,822
Capital lease obligations		2,379,250	—	(190,955)	2,188,295
Total other long term liabilities	$	2,589,255	8,547	(201,091)	2,396,711

The Authority's other long term liabilities as of December 31, 2014 are comprised of the following:

		Beginning Balance	Increases	Decreases	Ending Balance
Other long-term liabilities:					
Long term liabilities and unrealized credits	$	79,289	25,025	(7,023)	97,291
Borrowings		96,390	—	(4,611)	91,779
Claims and damages		21,183	1,200	(1,448)	20,935
Capital lease obligations		2,558,247	—	(178,997)	2,379,250
Total other long term liabilities	$	2,755,109	26,225	(192,079)	2,589,255

(12) Operations Services Agreement Employee Retirement Benefit Obligations

In accordance with the terms of the A&R OSA, the costs to employ PSEG Long Island's workforce, including employee pension and other post-employment benefits (OPEB), are a "pass through expenditure" to the Authority, and therefore a contractual liability of the Authority. PSEG Long Island employee pension and OPEB obligations are legal obligations of PSEG Long Island, and the employees covered by these plans are PSEG Long Island employees, not Authority employees.

To ensure that the NGRID workforce serving the Authority was neither better nor worse off by the transition from NGRID to PSEG Long Island, the PSEG Long Island benefit plans credited NGRID transitioned employees for service prior to the A&R OSA effective date for purposes such as eligibility, participation, vesting, company match levels, subsidies (including any type of early retirement subsidy) and attainment of retirement dates. In addition, those employees who immediately prior to the A&R OSA effective date could have become eligible to participate in the NGRID postretirement health and life insurance benefit plans, are entitled to receive substantially equivalent postretirement health and life insurance benefits under a postretirement health and life insurance plan established by PSEG Long Island. This arrangement created a prior service cost obligation totaling $126 million for pensions and $316 million for OPEBs. The following table provides a roll-forward of the changes to the benefit obligations and the fair value of the plan assets during each of the years in the periods ended December 31, 2015 and 2014. The liability decreased during 2015 due to the update of certain assumptions regarding the census data, claims costs, excise taxes, and the discount rate. These changes resulted in a net actuarial gain of $17 million for pensions and $118 million for OPEBs, of which $17 million and $25 million, respectively, are attributable to the increase in the market prevailing interest rates, which resulted in an increase in the assumed discount rate. Updated claims assumptions contributed $48 million and updated excise tax assumptions contributed $29 million to the actuarial gain.

(Amounts in thousands, unless otherwise stated)

The table also provides the funded status of the PSEG Long Island plans and the amounts recognized as the long term contractual liability on the Statements of Net Position at the end of both years. The table does not reflect the balance of the Authority's OPEB Account.

		Pension benefits		**Postretirement benefits**	
		2015	**2014**	**2015**	**2014**
Change in benefit obligation:					
Benefit obligation at beginning of year	$	194,971	—	452,072	—
Service cost		26,229	20,300	18,801	12,816
Interest cost		8,767	6,938	22,584	17,004
Actuarial loss (gain)		(17,351)	41,591	(117,793)	106,808
Benefits paid		(221)	(39)	(767)	(66)
Plan amendment		774	126,181	—	315,510
Benefit obligation at end of year		213,169	194,971	374,897	452,072
Change in plan assets:					
Fair value of assets at beginning of year		68,606	—	—	—
Actual return on plan assets		(1,997)	1,745	—	—
Employer contribution		30,000	66,900	767	66
Gross benefits paid		(221)	(39)	(767)	(66)
Fair value of assets at end of year		96,388	68,606	—	—
Funded status (Plan assets less benefit obligation):					
Authority unfunded obligation	$	(116,781)	(126,365)	(374,897)	(452,072)

In December 2014, the Authority's Board authorized the creation of an OPEB Account to allow the Authority to segregate funds to meet future OPEB obligations. During 2015 and 2014, the Authority deposited approximately $28 million and $20 million, respectively into its OPEB Account to meet future PSEG Long Island OPEB obligations. For a further discussion, see note 10.

(Amounts in thousands, unless otherwise stated)

The actuarial valuations related to pension and OPEB benefits involve estimates and assumptions regarding the probability of events in the future. Below are the weighted average assumptions used to calculate actuarial present values of benefit obligations at December 31, 2015 and 2014:

	Pension benefits		Postretirement benefits	
	2015	2014	2015	2014
Discount rate	4.92%	4.50%	4.97%	4.60%
Rate of compensation increase	3.25	3.25	3.25	3.25

Plan Assets

During 2015 and 2014, the Authority funded approximately $30 million and $67 million, respectively, to PSEG Long Island for deposit in its pension plan trust fund. The trust is sponsored, overseen and managed by the PSEG Thrift & Pension Investment Committee. The benefit plan assets are maintained separately by PSEG Long Island and are not commingled with other PSEG plans. The benefit plan assets are not assets of the Authority; and therefore, are not reflected on the Statements of Net Position. These assets, however, reduce the Authority's contractual obligation to PSEG Long Island for the benefit obligations of the PSEG Long Island employees. The following table outlines the PSEG Long Island pension assets as of December 31, 2015 and 2014:

		2015		2014	
Investment type		Amount	Allocation	Amount	Allocation
Equity	$	67,877	70	36,914	54
International		—	—	11,110	16
Fixed income		28,370	29	20,224	30
Other		141	1	—	—
	$	96,388	100%	68,248	100%

(13) Authority Employee Benefits

All full-time Authority employees must participate in one of two employee benefit plans offered by the Authority, either (i) the New York State or Local Retirement System (the Retirement System) or (ii) the New York State Voluntary Defined Contribution Plan (VDC).

(a) Pension Plans

Plan Description

The Retirement System is a cost-sharing multiple-employer defined benefit retirement system. The net position of the Retirement System is held in the New York State Common Retirement Fund (the Fund), which was established to hold all net assets and record changes in fiduciary net position allocated to the Retirement System. The Comptroller of the State of New York serves as the trustee of the Fund and is the administrative head of the Retirement System. Retirement System benefits are established under the provisions of the New York State Retirement and Social Security Law (NYSRSSL). Once a public employer elects to participate in the Retirement System, the election is irrevocable. The New York State Constitution provides that pension membership is a contractual relationship and plan benefits cannot be diminished or impaired. Benefits can be changed for future members only by enactment of a State statute. The Authority also participates in the Public Employees' Group Life Insurance Plan (GLIP), which provides death benefits in the form of life insurance. The Retirement System is included in the State's financial report as a pension trust fund. That report, including information with regard to benefits provided, may be found at www.osc.state.ny.us/retire/publications/index.php or obtained by writing to the New York State and Local Retirement System, 110 State Street, Albany, NY 12244.

The Retirement System uses a tier concept to distinguish membership classes (i.e. tiers 1 through 6) with tier membership based on the date an employee joins the System. The Retirement System is non-contributory for tiers 1 and 2 employees who joined on or prior to July 27, 1976. Tiers 3 and 4 employees, who joined between July 28, 1976 and December 31, 2009 and have less than ten years of service, contribute 3% of their salary. Tier 5 employees who joined on or after January 1, 2010 contribute 3 % of their salary during their entire length of service. Tier 6 employees who joined on or after April 1, 2013 contribute 3% of their salary through March 31, 2013 and up to 6% thereafter, based on their annual salary, during their entire length of service. Members become vested in the plan after ten years of service and generally are eligible to receive benefits at age 55. The benefit is generally 1.67 percent of final average salary (FAS) times the number of years of service, for members who retire with less than 20 years of service, and 2 percent of FAS for members who retiree with 20 or more years of service. The Retirement System provides an annual automatic cost of living adjustment to members or surviving spouses based on certain eligibility criteria.

Ordinary Disability Benefits

Generally, ordinary disability benefits, usually one-third of salary, are provided to eligible members after ten years of service; in some cases, they are provided after five years of service.

Accidental Disability Benefits

For all eligible Tier 1 and Tier 2 members, the accidental disability benefit is a pension of 75 percent of final average salary, with an offset for any Workers' Compensation benefits received. The benefit for eligible Tier 3, 4, 5 and 6 members is the ordinary disability benefit with the years-of-service eligibility requirement dropped.

Ordinary Death Benefits

Death benefits are payable upon the death, before retirement, of a member who meets eligibility requirements as set forth by law. The first $50,000 of an ordinary death benefit is paid in the form of group term life insurance. The benefit is generally three times the member's annual salary. For most members, there is also a reduced post-retirement ordinary death benefit available.

Post-Retirement Benefit Increases

A cost-of-living adjustment is provided annually to: (i) all pensioners who have attained age 62 and have been retired for five years; (ii) all pensioners who have attained age 55 and have been retired for ten years; (iii) all disability pensioners, regardless of age, who have been retired for five years; (iv) Retirement System recipients of an accidental death benefit, regardless of age, who have been receiving such benefit for five years and (v) the spouse of a deceased retiree receiving a lifetime benefit under an option elected by the retiree at retirement. An eligible spouse is entitled to one-half the cost-of-living adjustment amount that would have been paid to the retiree when the retiree would have met the eligibility criteria. This cost-of-living adjustment is a percentage of the annual retirement benefit of the eligible member as computed on a base benefit amount not to exceed $18,000 of the annual retirement benefit. The cost-of-living percentage shall be 50 percent of the annual Consumer Price Index as published by the U.S. Bureau of Labor, but cannot be less than 1 percent or exceed 3 percent.

Contributions

The Retirement System is noncontributory except for employees who joined the New York State and Local Employees' Retirement System after July 27, 1976, who contribute 3 percent of their salary for the first ten years of membership, and employees who joined on or after January 1, 2010 who generally contribute 3 percent of their salary for their entire length of service. Under the authority of the NYSRSSL, the Comptroller annually certifies the actuarially determined rates expressly used in computing the employers' contributions based on salaries paid during the Retirement Systems' fiscal year ending March 31. The Authority's contributions for the year ended December 31, 2015, 2014 and 2013, were equal to 100 percent of the contributions required, and were zero (due to credit provided), $0.9 million and $2 million, respectively.

Adoption of GASB No. 68 and No. 71

The Authority, effective January 1, 2015, adopted GASB Statement No. 68, *Accounting and Financial Reporting for Pensions*. Statement No. 68 requires governments, that provide defined benefit pension plans to their employees, to recognize their long term obligation for pension benefits as a liability and to more comprehensively and comparably measure the annual costs of pension benefits. Statement No. 68 also enhances accountability and transparency through revised and new note disclosures and required supplemental information. As a result of the implementation of Statement No. 68, net position as of January 1, 2014 was decreased by $1.3 million and is reflected as a cumulative effect of change in accounting principle in the statements of revenues, expenses and changes in net position. In addition, the Authority recognized approximately $195 thousand, as deferred outflows and $417 thousand as deferred inflows in the statement of net position at December 31, 2015, related to this implementation.

Also, effective January 1, 2015, the Authority adopted GASB Statement No. 71, *Pension Transition for Contributions Made Subsequent to the Measurement Date*, which is applied simultaneously with Statement No. 68. Statement No. 71 addresses the transition provisions of Statement No. 68, relating to amounts contributed by state or local government employers to a defined benefit pension plan after the measurement date of the government employer's beginning net pension liability. As the Authority had no contributions subsequent to March 31, 2015, this statement did not have an impact on the deferred outflows in the statement of net position at December 31, 2015.

(Amounts in thousands, unless otherwise stated)

Pension Liabilities, Pension Expense, and Deferred Outflows of Resources and Deferred Inflows of Resources Related to Pensions
At December 31, 2015, the Authority reported a liability of $0.9 million for its proportionate share of the net pension liability. The net pension liability was measured as of March 31, 2015, and the total pension liability used to calculate the net pension liability was determined by an actuarial valuation as of that date. The Authority's proportion of the net pension liability was based on a projection of the Authority's long-term share of contributions to the pension plan relative to the projected contributions of all participating members, actuarially determined.

At December 31, 2015 and 2014, the Authority's proportion was 0.03%.

For the year ended December 31, 2015, the Authority recognized pension expense of $0.8 million. At December 31, 2015, the Authority reported deferred outflows of resources and deferred inflows of resources related to pensions from the following sources:

	Deferred Outflows of Resources	Deferred Inflows of Resources
Differences between expected and actual experience	$ 30	-
Changes of Assumptions	-	-
Net difference between projected and actual earnings on pension plan investments	165	-
The Authority's contributions subsequent to the measurement date	-	417
	$ 195	417

(Amounts in thousands, unless otherwise stated)

The net amount of the Authority's balances of deferred outflows of resources and deferred inflows of resources related to pensions will be recognized in pension expense as follows:

Plan Years Ended December 31:		
2016	$	(56)
2017		(56)
2018		(55)
2019		(55)
2020		-
Thereafter		-
	$	(222)

Actuarial Assumptions
The total pension liability as of the measurement date was determined using an actuarial valuation as noted in the table below, with update procedures used to roll forward the total pension liability to measurement date. The actuarial valuation used the following assumptions:

Measurement date:	March 31, 2015
Actuarial valuation date:	April 1, 2014
Actuarial cost method:	Entry age normal
Inflation:	2.70%
Salary Scale:	4.90%
Investment rate of return, including inflation (compounded annually, net of expenses):	7.50%
Cost of living adjustments, annually:	1.40%
Decrement tables:	April 1, 2005- March 31, 2010 Retirement System's Experience
Mortality improvement:	Society of Actuaries Scale MP-2014

The long-term expected rate of return on pension plan investments was determined in accordance with Actuarial Standard of Practice (ASOP) No. 27, Selection of Economic Assumptions for Measuring Pension Obligations. ASOP No. 27 provides guidance on the selection of an appropriate assumed investment rate of return. Consideration was given to expected future real rates of return (expected returns, net of pension plan investment expense and inflation) for equities and fixed income as well as historical investment data and plan performance.

(Amounts in thousands, unless otherwise stated)

Best estimates of arithmetic real rates of return for each major asset class included in the target asset allocation as of March 31, 2015 and 2014 are summarized below:

Asset class	Target allocation	Long-term expected real rate of return
Domestic equity	38%	7.30%
International equity	13	8.55
Private equity	10	11.00
Real estate	8	8.25
Absolute return strategies	3	6.75
Opportunistic portfolio	3	8.60
Real assets	3	8.65
Bonds and mortgages	18	4.00
Cash	2	2.25
Inflation-Indexed bonds	2	4.00
	100%	

Discount Rate

The discount rate used to calculate the total pension liability was 7.5 percent. The projection of cash flows used to determine the discount rate assumes that contributions from plan members will be made at the current contribution rates and that contributions from the State will be made at statutorily required rates, actuarially. Based upon the assumptions, the Retirement System's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore the long term expected rate of return on pension plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

(Amounts in thousands, unless otherwise stated)

Sensitivity of the Net Pension Liability to the Discount Rate Assumption
The following presents the current-period net pension liability of the Authority's proportionate share of the net pension liability calculated using the current-period discount rate assumption of 7.5 percent, as well as what the net pension liability would be if it were calculated using a discount rate that is 1-percentage-point lower (6.5 percent) or 1-percentage-point higher (8.5 percent) than the current assumption:

	1% Decrease (6.5%)	**Current Assumption (7.5%)**	**1% Increase (8.5%)**
Authority's proportionate share of the net pension liability (asset)	$6 million	$947 thousand	$(4) million

(b) Deferred Compensation and Savings Plans

The Authority offers certain full-time employees participation in a Voluntary Defined Contribution Plan, which is an alternative to the State's existing defined benefit pension systems. This defined contribution plan option is available to all unrepresented State, New York City, and local public employees who are hired on or after July 1, 2013 and are paid at a rate of $75,000 or more on an annual basis. For those employees choosing this option, the Authority is required to contribute 8% of their gross salary. An independent trustee is responsible for the administration of this plan.

(c) Deferred Savings Plans

The Authority also offers employees a deferred compensation plan created in accordance with the Internal Revenue Code, Section 457. This plan permits participants to defer a portion of their salaries until future years. Amounts deferred under the plan are not available to employees or beneficiaries until termination, retirement, death or unforeseeable emergency. An independent trustee is also responsible for the administration of this plan.

(d) Other Postemployment Benefits

The Authority is a participating employer in the New York State Health Insurance Program (NYSHIP), which is administered by the New York State Department of Civil Service, as an agent multiple employer defined benefit plan. Through NYSHIP, the Authority provides certain health care for eligible retired employees and their dependents. Article XI of the New York State Civil Service Law assigns the authority to NYSHIP to establish and amend the benefit provisions of the plans and to establish maximum obligations of the plan members to contribute to the plan. The Authority's Board is authorized to establish the contribution rates of its employees and retirees below those set by Civil Service Law. Participation in the NYSHIP program provides for employees and/or their dependents to continue eligibility for these benefits in retirement if the employee had at least one year of full-time service with the Authority, and satisfied the requirements for retiring as a member of the Retirement System or is enrolled in the VDC. Eligible retirees contribute 10% of the cost of single coverage and 25% of the cost of dependent coverage for health insurance benefits. Participants included approximately 80 Authority employees and retired and/or spouses of retired employees who were eligible to receive these benefits at December 31, 2015. NYSHIP does not issue a stand-alone financial report and NYSHIP's agent activities are included within the financial statements of the State.

The Authority accounts for its OPEB obligations, in accordance with GASB No. 45, *Accounting and Financial Reporting for Post-Employment Benefits Other Than Pensions*. Actuarial valuations involve estimates of the value of reported amounts and assumptions about the probability of events in the future. Examples include assumptions about employment mortality and the healthcare cost trend. Amounts determined regarding the annual required contributions of the employer are subject to continual revision as actual results are compared to past expectations and new estimates are made about the future.

The Authority's annual OPEB cost for the plan is calculated based on the Annual Required Contribution (ARC), an amount actuarially determined in accordance with the parameters of GASB No. 45. GASB No. 45 does not require that an employer actually fund its ARC, but allows for the financing of these benefits on a pay-as-you-go basis. The ARC in future periods represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost each year, actuarial assumptions and plan changes, and interest on the unfunded actuarial liability. Amounts "required" but not actually set aside to pay for these benefits are accumulated as part of the net OPEB obligation.

(Amounts in thousands, unless otherwise stated)

The following table shows the components of the Authority's annual OPEB cost and the changes in the Authority's net OPEB obligation as recorded in long term liabilities:

		2015	2014	2013
Annual OPEB cost:				
Annual required contribution (ARC):				
Normal cost	$	984	937	1,175
Amortization payment		24,726	23,444	23,451
Interest to the end of the year		-	-	-
Total		25,710	24,381	24,626
ARC adjustment		(24,726)	(25,007)	(25,303)
Interest on net OPEB obligation		755	764	772
Annual OPEB cost	$	1,739	138	95
Net OPEB obligation:				
Net OPEB obligation at beginning of year	$	23,971	24,243	24,530
Annual required contribution:				
Annual OPEB cost		1,739	138	95
Employer contribution:				
Retiree benefit payments during year		(501)	(410)	(382)
Net OPEB obligation at year end	$	25,209	23,971	24,243

The funding of the Authority's net OPEB obligation is at the discretion of management and the Board. The net OPEB obligation is paid on a pay-as-you-go basis. However, during 2015, the Board authorized the creation of an OPEB Account to fund in advance the OPEB obligations of both the Authority and the PSEG Long Island employees (as discussed above). As such as of December 31, 2015 and 2014, the Authority deposited $1.2 million and $2.1 million, respectively, into this account to meet the OPEB obligations of Authority employees, which deposits are not reflected in the table above.

Projections of benefits for financial reporting purposes are based on the substantive plan (the plan as understood by the employer and plan members) and include the types of benefits provided at the time of each valuation. The actuarial methods and assumptions used include techniques that are designed to reduce short-term volatility in actuarial accrued liabilities and the actuarial value of assets, consistent with the long-term perspective of the calculations. For 2015 and 2014 actuarial valuation, the projected unit credit actuarial cost method was used. For 2015 and 2014, the actuarial assumptions included an investment rate of return (net of administrative expenses) of 3.15%. The medical trend assumption begins at 8.25% and decreases to a 4.75% long-term trend rate after eight years. The drug trend assumption begins at 6.75% and decreases to a 4.75% long-term trend rate after eight years. The Medicare Part B trend assumption begins at 5.50% and decreases to a 4.75% long-term trend rate after six years.

(14) Commitments and Contingencies

(a) Amended and Restated Power Supply Agreement

The A&R PSA, which became effective on May 28, 2013, is the successor agreement to the original PSA between NGRID and LIPA. The A&R PSA provides for the sale to the Authority by NGRID of all the capacity, energy and, ancillary services from the oil and gas fired generating plants on Long Island formerly owned by LILCO. Sales are made at cost based wholesale rates regulated by the Federal Energy Regulatory Commission (FERC). The rates may be modified in accordance with the terms of the A&R PSA for: (i) agreed upon labor and expense indices applied to the base year; (ii) a return of and return on net capital additions, which require approval by the Authority; and (iii) certain reasonably incurred expenses that are outside of the control of NGRID. The annual capacity charge in 2015 and 2014 was $456 million and $440 million, respectively. The variable charge under both the PSA and A&R PSA is constant at $0.90/MWH of electric energy generated by the plants.

The A&R PSA has provisions for penalties in the event that annual guarantees for heat rate and unforced capacity (UCAP) are not met. No penalties were assessed in either 2015 or 2014 under the A&R PSA.

Included in the annual capacity charge are pension and other post-employment benefit (P&OPEB) expenses of NGRID employees. Each contract year, the annual capacity charge is adjusted through a single purpose filing with FERC, in mid-year, to reflect the actuarially determined amounts of P&OPEB expense for that contract year. Although the Authority has consistently funded the annual plan costs through the PSA and the A&R PSA annual capacity charge, NGRID has asserted that the pension and OPEB obligations are underfunded. The nature and extent of the Authority’s potential obligation for these underfunded plans is being assessed and the Authority, at this preliminary stage, cannot predict or estimate any possible liability.

(b) Power Purchase and Transmission Agreements

The Authority has entered into power purchase agreements (PPAs) with several private companies to develop and operate generating units at sites throughout Long Island. Generally, the PPAs provide for the Authority to purchase 100% of the capacity, (and associated energy and ancillary services as needed), for the term of each contract, which vary in duration up to 30 years from commercial operation date. Additionally, the Authority has entered into PPAs with several private companies for capacity and/or energy from facilities that are not located on Long Island but which are delivered to Long Island via undersea cables. These undersea cables are under long term firm transmission capacity purchase agreements (FTCPAs) with the Authority. These PPAs and FTCPAs have been accounted for as capitalized lease obligations on the Statements of Net Position.

(Amounts in thousands, unless otherwise stated)

The Authority has also entered into several agreements to purchase renewable energy from on and off Long Island sources. Certain of these power producing facilities have also been accounted for as capitalized lease obligations. The Authority also had various firm, noncancelable purchase power commitments that do not meet the criteria for capitalization and are being accounted for as operating leases.

The following table presents estimated future payments pertaining to purchase power commitments with remaining terms greater than one year for both capital and operating leases:

		Capital leases	**Operating leases**
Minimum lease/rental payments:			
2016	$	312,944	277,310
2017		302,529	244,598
2018		277,367	197,366
2019		256,886	183,535
2020		251,144	159,259
2021 through 2025		1,196,512	428,909
2026 through 2030		589,203	423,824
2031 through 2035		58,300	77,002
2036 through 2038		—	38,402
Total		3,244,885	2,030,205
Less imputed interest		865,635	—
Net present value	$	2,379,250	2,030,205

As provided by the Authority's tariff, the costs of all of the facilities noted above are includable in the calculation of Fuel and Purchased Power Cost. As such, these costs are expected to be recoverable through the FPPCA.

(c) Office Lease

The Authority's office lease agreement includes scheduled base rent increases and rent "holidays" over the term of the lease. The total amount of the base rent payments is charged to expense on the straight-line method over the term of the lease. The termination date of the new lease agreement is April 30, 2024. The Authority recorded a deferred credit to reflect the excess of rent expense over cash payments since inception of the lease.

(Amounts in thousands, unless otherwise stated)

The future minimum payments under these leases are as follows for the years ended:

For the period ended,		
2016	$	1,629
2017		1,682
2018		1,736
2019		1,792
2020		1,851
2021 through 2025		6,608
Total	$	15,298

(d) Insurance Programs

The Authority's insurance program is comprised of a combination of policies, from major insurance companies, self-insurance, and contractual transfer of liability, including naming the Authority as an additional insured and indemnification.

The Authority has purchased Workers' Compensation insurance from the New York State Insurance Fund to provide coverage for claims arising from employee injuries. In addition, the Authority carries Employment Practices Liability Insurance from a major insurance company and the Authority's office property and liability coverage is administered by New York State Office of General Services Bureau of Risk & Insurance Management through a master policy the State procures for various State entities, including the Authority. Liability related to construction projects and similar risks is transferred through contractual indemnification and compliance with Authority insurance requirements. The Authority also has insurance coverage on its interest in NMP2 as disclosed in detail in note 8.

The Authority has commercially available excess general liability and property insurance for claims above its self-insurance provisions. For general liability, including automobile liability, the Authority is self-insured up to $3 million. For property damage and extra expense combined, the Authority is self-insured up to $1.5 million per occurrence. In addition, for substation assets valued at $50 million or greater, the Authority is self-insured up to $2.5 million per occurrence. For property damage or loss due to a named windstorm and flood, 2% of the value at risk is self-insured per occurrence with a minimum of $1.5 million and up to a maximum self-insured level of $7.5 million.

The Authority has no general property insurance for damage to its poles and wires and is self-insured.

(15) Legal Proceedings

(a) PSEG Long Island

In accordance with the A&R OSA, PSEG Long Island is not entitled to payment from the Authority for any losses attributable to a third party claim arising from any negligent act, omission or willful misconduct by PSEG Long Island in performing its obligations to operate and maintain the Authority's T&D system. Other than losses attributable to PSEG Long Island's gross negligence or willful misconduct for which there is no limitation on PSEG Long Island's liability, PSEG Long Island's liability for third party claims is generally limited to amounts above $2.5 million in the aggregate in one year up to a maximum aggregate amount of $2.5 million in any contract year. PSEG Long Island is not responsible for any liabilities that occurred prior to January 1, 2014.

(a) Superstorm Sandy

Four purported class actions were filed against the Authority and NGRID related to Superstorm Sandy that contain common allegations of wrongdoing and/or gross negligence relating to the Authority's and NGRID's preparedness for and response to the storm. All of these actions seek monetary damages, fees and other relief. 12 more individual actions have been filed on behalf of the owners of approximately 100 properties in the Breezy Point, Belle Harbor and Rockaway Park neighborhoods of the Rockaway Peninsula, in the Queens portion of the Service Territory. These suits allege generally that the failure to de-energize the electrical system in the Rockaways in advance of the tidal surges experienced during the storm resulted in fires that caused various types of property damage, ranging from all or partial loss of customers' homes. The class action cases and the fire cases are being defended, and although the amounts sought in damages are material, the outcome of these matters cannot be predicted with certainty at this time. The Authority does not believe that they will have a material impact on the operating results or financial condition of the Authority.

(b) Environmental

NGRID and the Authority are parties to the Liabilities Undertaking and Indemnification Agreements which, when taken together, provide, generally, that environmental liabilities will be divided between NGRID and the Authority on the basis of whether they relate to assets transferred to NGRID or retained by the Authority as part of the 1998 LIPA/LILCO Merger (Merger). In addition, to clarify and supplement these agreements, NGRID and the Authority also entered into an agreement to allocate between them certain liabilities, including environmental liabilities, arising from events occurring prior to the Merger and relating to the business and operations to be conducted by the Authority after the Merger (the Retained Business) and to the business and operations to be conducted by NGRID after the Merger (the Transferred Business).

NGRID is responsible for all liabilities arising from all manufactured gas plant operations on Long Island (MGP Sites), including those currently or formerly operated by NGRID or any of its predecessors, whether or not such MGP Sites related to the Transferred Business or the Retained Business. In addition, NGRID is liable for all environmental liabilities traceable to the Transferred Business and certain scheduled environmental liabilities. Environmental liabilities that arise from the nonnuclear generating business may be recoverable by NGRID as part of the capacity charge under the A&R PSA. The Authority is responsible for all environmental liabilities traceable to the Retained Business and certain scheduled environmental liabilities.

Environmental liabilities other than those related to MGP sites that existed as of the date of the Merger that are untraceable, including untraceable liabilities that arise out of common and/or shared services have been allocated to the Authority and NGRID, as provided for in the Merger.

The A&R PSA addresses the terms by which the Authority will continue to purchase electricity from certain NGRID facilities. Generally, NGRID's liabilities under this contract are limited to losses due to gross negligence or willful misconduct or violations of environmental laws not consistent with prudent utility practices.

(c) Environmental Matters Retained by the Authority

Superfund Sites – Under Section 107(a) of the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA, also commonly referred to as Superfund), parties that generated or arranged for disposal of hazardous substances are liable for costs incurred by the Environmental Protection Agency (EPA) or others that are responding to a release or threat of release of the hazardous substances.

Port Washington Landfill – LILCO is a Potentially Responsible Party (PRP) at this 54-acre municipal solid waste landfill located in the Town of North Hempstead. The landfill operated from 1973 to 1983. The New York State Attorney General is seeking to recover Environmental Quality Bond Act funds advanced to the Town of North Hempstead so it could properly close out the site with oversight by the New York State Department of Environmental Conservation (DEC). The landfill has been remediated and this matter is only concerned with cost recovery. Beginning in January 2001, LILCO and 11 other parties signed a series of tolling agreements with the Attorney General to extend the statute of limitations under CERCLA. Six of the 11 tolling agreement PRPs, including LILCO, have formed a Joint Defense Group (JDG) that acts as one with respect to dealing with the Attorney General. In August 2013, the Attorney General accepted JDG's settlement offer of $1.8 million. A consent decree was subsequently executed by the JDG and the Attorney General and accepted by the federal court (EDNY). The Authority's contribution to the settlement is approximately $260 thousand, which will not have a material impact on the Authority's operating results or financial condition. JDG's third and final settlement payment, due in March 2016, has been made and the JDG's monitoring obligation is concluded.

Metal Bank – Cottman Avenue is a site with PCB contamination on the Delaware River in Philadelphia Pennsylvania. In 2005, EPA sued and subsequently settled with a number of utility companies as PRPs – including LILCO – for allegedly sending used transformers to the site during the 1960s and 1970s. The remediation has been completed and monitoring at the site continues. The Authority's contribution toward the settlement and monitoring costs has not been material. The National Oceanic and Atmospheric Administration (NOAA) notified the PRP group that it (NOAA) will be initiating discussions about natural resource damages for marine resources. After NOAA performs a preliminary assessment study to determine whether injury to natural resources has occurred, and if so, the severity, NOAA will quantify that injury, and then consider possible restoration projects, such as replanting wetlands and restoring fish. The PRP group is currently evaluating NOAA's claims regarding alleged natural resource damages. The Authority is unable to estimate potential liability, but believes that it would not have a material impact on the operating results or financial condition of the Authority. EPA has notified the PRP group of concerns about PCB contamination at another former Metal Bank facility located on State Road in Philadelphia. The PRP group is currently evaluating EPA's claims regarding the State Road site. At this preliminary stage the Authority is unable to estimate potential liability, but believes that it would not have a material impact on the Authority's operating results or financial condition.

(d) Asbestos Proceedings

Litigation is pending in State Court against the Authority, LILCO, NGRID and various other defendants, involving thousands of plaintiffs seeking damages for personal injuries or wrongful death allegedly caused by exposure to asbestos. The cases for which the Authority may have financial responsibility involve employees of various contractors and subcontractors engaged in the construction or renovation of one or more of LILCO's six major power plants. These cases include extraordinarily large damage claims, which have historically proven to be excessive. The actual aggregate amount paid to plaintiffs alleging exposure to asbestos at LILCO power plants over the years has not been material to the Authority. Due to the nature of how these cases are litigated, it is difficult to determine how many of the remaining cases that have been filed (or of those that will be filed in the future) involve plaintiffs who were exposed to asbestos at any of the LILCO power plants. Based upon experience, it is likely that the Authority will have financial responsibility in a significantly smaller percentage of cases than are currently pending (or which will be filed in the future) involving plaintiffs who allege exposure to asbestos at any of the LILCO power plants.

(16) Subsequent Events

On March 1, 2016, the UDSA issued approximately $636.8 million of 2016A Restructuring Bonds to refund a portion of the Authority's existing debt. This refunding will produce a net present value savings of approximately $115 million and is expected to be completed in April 2016.

In March 2016, the Authority reached a settlement agreement with its insurer for losses related to the damage to the Authority's T&D system caused by Superstorm Sandy. A portion of the approximate $80 million gross insurance claim settlement will be duplicative to the grant funding from FEMA for Superstorm Sandy costs. The Authority is currently unable to estimate the amount to be considered as a duplication of benefits.

The Board has authorized the Authority staff to net the book value gain of the insurance settlement, once finalized, against the regulatory assets previously approved by the Board for the installation of an outage management system and enterprise resource planning system.

LONG ISLAND POWER AUTHORITY
(A Component Unit of the State of New York)

Consolidating Statement of Revenues, Expenses, and Change in Net Position

Year ended December 31, 2015

(Amounts in thousands)

		Authority	UDSA	Eliminations	Consolidated
Operating revenues – electric sales	$	3,432,051	73,158	—	3,505,209
Other revenues		1,161	—	(1,161)	—
Total revenues		3,433,212	73,158	(1,161)	3,505,209
Operating expenses:					
Operations – fuel and purchased power		1,510,725	—	—	1,510,725
Operations and maintenance		813,331	846	—	814,177
Operations and maintenance-amortizations		11,403	—	—	11,403
Storm restoration		63,210	—	—	63,210
General and administrative		21,663	1,590	(1,161)	22,092
Depreciation and amortization		223,607	—	—	223,607
Amortization of restructuring property		(15,672)	15,672	—	—
Pass through taxes under certain long-term operating agreements		192,729	—	—	192,729
Payments in lieu of taxes		349,440	—	—	349,440
Total operating expenses		3,170,436	18,108	(1,161)	3,187,383
Operating income		262,776	55,050	—	317,826
Nonoperating revenue and expenses:					
Other income, net:					
Investment income		5,845	33	—	5,878
Grant Income – FEMA		13,472	—	—	13,472
Grant Income – other		40,857	—	—	40,857
Carry charges on regulatory assets		27,594	—	—	27,594
Other		4,272	—	—	4,272
Total other income, net		92,040	33	—	92,073
Interest charges and (credits):					
Interest on long-term debt, net		260,177	94,948	—	355,125
Other interest		13,713	—	—	13,713
Allowance for borrowed funds used during construction		3,094	(10,207)	—	(7,113)
Total interest charges and (credits)		276,984	84,741	—	361,725
Change in net position	$	77,832	(29,658)	—	48,174

See paragraph on Supplementary and Other Information included in independent auditor's report.

LONG ISLAND POWER AUTHORITY
Required Supplementary Information

SCHEDULE OF THE AUTHORITY'S PROPORTIONATE SHARE OF THE NET PENSION LIABILITY

NYSLRS Pension Plan
Last 10 Fiscal Years*

	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
The Authority's proportion of the net pension liability (asset)									0.0280362%	0.0280362%
The Authority's proportionate share of the net pension liability (asset)									$ 947,131	$ 1,266,916
The Authority's covered-employee payroll									$ 4,787,173	$ 5,472,436
The Authority's proportionate share of the net pension liability (asset) as a percentage of its covered-employee payroll									19.78%	23.15%
Plan fiduciary net position as a percentage of the total pension liability									97.95%	97.20%

*The amounts presented for each fiscal year were determined as of the measurement date of the plans.

This schedule is presented to illustrate the requirement to show information for 10 years. However, until a full 10-year trend is compiled, the Authority has presented information for those years for which information is available.

See paragraph on Supplementary and Other Information included in independent auditor's report.

KPMG LLP
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New York, NY 10154-0102

Independent Auditors' Report on Internal Control Over Financial Reporting and on Compliance and Other Matters Based on an Audit of Financial Statements Performed in Accordance With *Government Auditing Standards*

The Board of Trustees
Long Island Power Authority:

We have audited, in accordance with auditing standards generally accepted in the United States of America; the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States, the basic financial statements of the Long Island Power Authority (the Authority), which comprise the statements of net position as of December 31, 2015 and 2014, and the related statements of revenues, expenses, and changes in net position, and cash flows for the years then ended, and the related notes to the basic financial statements, and have issued our report thereon dated March 21, 2016.

Internal Control Over Financial Reporting

In planning and performing our audit of the basic financial statements as of and for the year ended December 31, 2015, we considered the Authority's internal control over financial reporting (internal control) to determine the audit procedures that are appropriate in the circumstances for the purpose of expressing our opinion on the basic financial statements, but not for the purpose of expressing an opinion on the effectiveness of the Authority's internal control. Accordingly, we do not express an opinion on the effectiveness of the Authority's internal control.

Our consideration of internal control was for the limited purpose described in the preceding paragraph and was not designed to identify all deficiencies in internal control that might be material weaknesses or significant deficiencies and therefore, material weaknesses or significant deficiencies may exist that have not been identified. However, as described below, we identified certain deficiencies in internal control that we consider to be a significant deficiency.

A deficiency in internal control exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct, misstatements on a timely basis. A material weakness is a deficiency, or a combination of deficiencies, in internal control such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected, on a timely basis.

A significant deficiency is a deficiency, or a combination of deficiencies, in internal control that is less severe than a material weakness, yet important enough to merit attention by those charged with governance. We consider the deficiency described below to be a significant deficiency.

PSEG Long Island manages and hosts the Authority's billing and customer information technology systems (CAS & EBO). A significant deficiency was identified over the monitoring controls of access to the development and production environments resulting in the risk that certain individuals could develop changes to the system configuration and put those changes into production without appropriate monitoring or detective controls in place.

KPMG

Management's Response

During KPMG's audit, a separation of duties deficiency was identified. It is PSEG Long Island's position that the current System Administrator access is a standard practice and required to perform maintenance activities in CAS/EBO. Entitlement reviews within Customer Operations control all CAS/EBO access and validates each user's need with appropriate management. In addition, there are mitigating financial controls that PSEG Long Island's Finance team performs including analytical reviews of monthly revenue variances by customer segment to review variances to plan as well as reviews of customer usage and revenue within Customer Operations.

PSEG Long Island did internally review and confirm that all file access and changes performed by the System Administrators who do have access to both development and production environments are being logged. PSEG Long Island already monitors the daily "RACF Violation" and "Special Access" reports which are captured in the PageCenter tool. Also, all moves from development to production are approved and tracked through the PSEG Long Island change management process.

As a result of the above limited exposure, Information Technology monitoring, and mitigating financial controls, PSEG Long Island views this control deficiency as a low risk to the Authority, however PSEG Long Island has agreed to institute an additional control to monitor System Administrator activity. Our mainframe security team is in the process of documenting a procedure for further monitoring and we are estimating that it will take 30-60 days to have the custom security report in place to support the monitoring of System Administrator activities.

Response to Finding

Management's response to the significant deficiency identified in our audit is described previously. The response was not subjected to the auditing procedures applied in the audit of the basic financial statements and, accordingly, we express no opinion on the response.

Compliance and Other Matters

As part of obtaining reasonable assurance about whether the Authority's basic financial statements are free from material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of our audit, and accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance or other matters that are required to be reported under *Government Auditing Standards*.

Purpose of this Report

The purpose of this report is solely to describe the scope of our testing of internal control and compliance and the result of that testing, and not to provide an opinion on the effectiveness of the Authority's internal control or on compliance. This report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the Authority's internal control and compliance. Accordingly, this communication is not suitable for any other purpose.

KPMG LLP

New York, NY
March 21, 2016

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CORPORATE STATISTICS

Customers

	Number	GWh Sales
Residential	1,002,942	9,611
Commercial	114,648	9,730
Street Lighting	5,383	144
Other Public Authorities	131	441
Total	**1,123,104**	**19,926**

System Data

Transmission system	1,378 miles
Distribution system	13,846 miles
Number of transmission substations	28
Number of distribution substations	149

	2015	2014
Total Retail Energy Requirements (GWhs)	21,061	20,785
Generation (MWs)		
Capacity	5,835	5,883
Peak Demand (Summer)	5,049	4,859
Weather Normalized Peak	5,285	5,338
Financial (Thousands)		
Total Assets and Deferred Outflows	13,034,640	13,195,652
Utility Plant, Property and Equipment	7,548,163	6,727,057
Par Amount of Debt	7,650,034	7,809,050
Capital Lease Obligations	2,379,250	2,558,247
Total Debt and Capital Lease Obligations	10,029,284	10,367,297
Net Position	481,499	434,592
Debt/Capitalization Ratio	95.4%	96.0%
Fixed Obligation Coverage Ratio		
Excluding UDSA	1.19x	1.21x
Including UDSA	1.17x	1.16x

Long Island Power Authority
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