ANNUAL REPORT

OF THE

LONG ISLAND POWER AUTHORITY

AND THE LONG ISLAND LIGHTING COMPANY d/b/a LIPA

For The 2011 Fiscal Year

As Required By Certain

Continuing Disclosure Certificates

Executed With Respect To The Following Bonds:

Electric System General Revenue Bonds, Series 1998A
Electric System General Revenue Bonds, Series 2000A
Electric System General Revenue Bonds, Series 2001A
Electric System General Revenue Bonds, Series 2003B
Electric System General Revenue Bonds, Series 2003C
Electric System General Revenue Bonds, Series 2003I-O
Electric System General Revenue Bonds, Series 2004A
Electric System General Revenue Bonds, Series 2006A-B
Electric System General Revenue Bonds, Series 2006C-D
Electric System General Revenue Bonds, Series 2006E
Electric System General Revenue Bonds, Series 2006F
Electric System General Revenue Bonds, Series 2008A
Electric System General Revenue Bonds, Series 2008B
Electric System General Revenue Bonds, Series 2009A
Electric System General Revenue Bonds, Series 2010A
Electric System General Revenue Bonds, Series 2010B
Electric System General Revenue Bonds, Series 2011A

and

NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

Adjustable Rate Pollution Control Revenue Bonds (Long Island Lighting Company Project), 1985 Series A and 1985 Series B

Electric Facilities Revenue Bonds (Long Island Lighting Company Project), 1993 Series B, 1994 Series A and 1995 Series A

(See Appendix A for a List of Applicable CUSIP Numbers)

TABLE OF CONTENTS

Page

ANNUAL REPORT

of the

LONG ISLAND POWER AUTHORITY

and the

LONG ISLAND LIGHTING COMPANY d/b/a LIPA

For The 2011 Fiscal Year

As Required By Certain

Continuing Disclosure Certificates

INTRODUCTION

This Annual Report for the year ended December 31, 2011 (together with the Appendices attached hereto, the "Annual Report") is furnished by the Long Island Power Authority, a corporate municipal instrumentality and political subdivision of the State of New York (the "Authority") and by its wholly-owned subsidiary, the Long Island Lighting Company ("LILCO") which does business under the name LIPA ("LIPA"), to provide the information regarding the Authority and LIPA required by the various Continuing Disclosure Certificates described below (the "Continuing Disclosure Certificates").

This Annual Report is being filed to satisfy the Authority and LIPA's undertakings under the Continuing Disclosure Certificates executed and delivered by the Authority or LIPA relating to the following bonds:

The Authority's Electric System General Revenue Bonds, Series 1998A, issued on May 28, 1998.

The Authority's Electric System General Revenue Bonds, Series 2000A, issued on May 3, 2000.

The Authority's Electric System General Revenue Bonds, Series 2001A, issued on March 29, 2001.

The Authority's Electric System General Revenue Bonds, Series 2003B, issued on April 30, 2003.

The Authority's Electric System General Revenue Bonds, Series 2003C, issued on May 15, 2003.

Certain of the Authority's Electric System General Revenue Bonds, Series 2003I - Series 2003O, issued on May 29, 2003.

The Authority's Electric System General Revenue Bonds, Series 2004A, issued on August 12, 2004.

The Authority's Electric System General Revenue Bonds, Series 2006A and Series 2006B, issued on March 21, 2006.

The Authority's Electric System General Revenue Bonds, Series 2006C and Series 2006D, issued on July 26, 2006.

The Authority's Electric System General Revenue Bonds, Series 2006E, issued on September 26, 2006.

The Authority's Electric System General Revenue Bonds, Series 2006F, issued on December 20, 2006.

The Authority's Electric System General Revenue Bonds, Series 2008A, issued on October 16, 2008.

The Authority's Electric System General Revenue Bonds, Series 2008B, issued on November 6, 2008.

The Authority's Electric System General Revenue Bonds, Series 2009A, issued on January 28, 2009.

The Authority's Electric System General Revenue Bonds, Series 2010A and Series 2010B, issued on May 18, 2010.

The Authority's Electric System General Revenue Bonds, Series 2011A, issued on September 28, 2011.

New York State Energy Research and Development Authority's ("NYSERDA") Adjustable Rate Pollution Control Revenue Bonds (Long Island Lighting Company Project), 1985 Series A and 1985 Series B, converted to a fixed rate as of March 1, 1999.

NYSERDA's Electric Facilities Revenue Bonds (Long Island Lighting Company Project), 1993 Series B, 1994 Series A and 1995 Series A, converted to a fixed rate as of March 1, 1999.

Attached to this Annual Report as Appendix A is a listing of the CUSIP numbers of the bonds of the Authority and NYSERDA listed above as to which the Continuing Disclosure Certificates and this Annual Report relate.

Certain of the information contained in this Annual Report may be in addition to that required by the Continuing Disclosure Certificates. Pursuant to the terms of the Continuing Disclosure Certificates, the Authority and LIPA are under no obligation to update such additional information in the future or include it in any future annual report.

OPERATING RESULTS

The operating results of the Authority and LIPA for the years ended December 31, 2011 and 2010 are contained in the audited basic financial statements included as Appendix B hereto.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND CONSOLIDATED RESULTS OF OPERATIONS FOR THE YEAR ENDED DECEMBER 31, 2011

Management's Discussion of Financial Condition and Consolidated Results of Operations for the year ended December 31, 2011 is contained in Appendix B hereto and is incorporated by reference herein.

CAPITAL IMPROVEMENT PLAN

Capital expenditures including Nine Mile Point 2 ("NMP2") expenditures for the years 2007 through 2011 were $300 million, $297 million, $278 million, $249 million and $303 million, respectively. Such expenditures included interconnection costs associated with the undersea cable from Sayreville, New Jersey and the new generating stations on Long Island, reliability enhancements, capability expansion, new customer connections, facility replacements and public works. Capital expenditures for 2012 in the approved budget are approximately $321 million. The 2012 capital expenditure program provides for a continuation of the historical programs to maintain reliability and quality of electric service, as well as expenditures for capability expansion, new customer connections, facility replacements, reliability enhancements and public work projects that were comparable to historical levels.

As shown in the table below, LIPA's 18 percent share of capital expenditures for NMP2 during the period 2007 through 2011 averaged approximately $24.2 million annually for plant modifications including the power uprate and nuclear fuel purchases. After the power uprate, capital expenditures for NMP2 plant modifications should return to a level approximately consistent with historical average spending levels, excluding fuel.

LIPA's 18% Share of NMP2 Capital Expenditures
(in millions)

Year	Plant Modifications	Fuel	Total
2007*	4.6	13.2	17.8
2008	4.8	0.5	5.3
2009*	4.5	20.6	25.1
2010	31.7	2.5	34.2
2011	12.7	25.8	38.5

* Year of a refueling or fuel purchase.

SYSTEM LOADS AND RESOURCES

Historical Power and Energy Requirements

Electricity usage patterns and seasonal weather conditions in LIPA's service area result in maximum electrical demand during the summer season and relatively low load factors on an annual basis. The table below shows LIPA's peak demand and weather-normalized peak load for the period 2007 through 2011.

Year	Peak Demand (MW)	Weather Normalized (MW)
2007	5,247	5,239
2008	5,130	5,284
2009	5,034	5,208
2010	5,719	5,303
2011	5,771	5,285

[Remainder of Page Intentionally Left Blank]

The following table sets forth historical annual peak demands and energy requirements for the period 2007 through 2011.

Historical Loads and Resources

	2007	2008	2009	2010	2011
Annual Peak Demand (Summer) (MW)[1]	5,247	5,130	5,034	5,719	5,771
Capacity (MW)[2]					
Nuclear[3]	205	205	206	206	225
Purchased Capacity:					
GENCO					
Steam[4]	2,669	2,685	2,707	2,707	2,699
Other[4]	1,372	1,375	1,371	1,367	1,311
Other Purchased Capacity[5]	1,446	1,357	1,618	2,055	2.092
Total Purchased Capacity	5,487	5,417	5,696	6,128	6,102
Total Capacity	5,692	5,622	5,902	6,334	6,327
Annual Reserve Margin:					
MW[6]	445	492	868	615	556
Percent	8.5	9.6	17.2	10.8	9.6
Energy (MWh)					
Total Energy Requirements[7]	21,609,275	21,389,895	20,727,286	21,806,828	21,583,426
Generating Resources:					
Nuclear[3]	1,635,958	1,536,078	1,785,593	1,590,821	1,707,140
Purchased Energy:					
GENCO					
Steam	8,626,630	6,748,379	4,900,602	5,883,018	5,472,453
Other	261,139	261,035	192,397	234,331	189,461
Other Purchased Energy	11,085,548	12,844,403	13,848,694	14,098,658	14,214,372
Total Purchased Energy	19,973,317	19,853,817	18,941,693	20,216,007	19,876,286
Total Energy	21,609,275	21,389,895	20,727,286	21,806,828	21,583,246

1 Includes peak demand load for Long Island Choice load and Power-for-Jobs.

2 Summer capacity rating as measured in October of each year. Includes capacity under contract to LIPA.

3 LIPA's 18 percent share of NMP2.

4 Values from National Grid Corporate Services.

5 Includes on- and off-Island resources under contract at time of peak. Resources include capacity associated with Independent Power Producers, firm capacity purchases, Power-for-Jobs, and power supply agreements. Excludes short-term bi-lateral and NYISO capacity market auction purchases.

6 Equal to capacity less demand.

7 Includes energy requirements for Power-for-Jobs, Long Island Choice and the Grumman campus.

Existing Power Supply Resources

Pending the results of the competitive solicitation issued in August 2010, which is expected later this year, LIPA is expected to rely on existing power supply resources, including those described in this section and below under "Certain Additions to Power Supply Resources," to meet the bulk of its capacity and energy requirements. The table shown above sets forth the historical annual contribution of the National Grid Generation LLC ("GENCO") facilities, the NMP2 facility ("Nuclear"), and Independent Power Producers on Long Island and elsewhere. Combined, these resources were able to provide the service area's capacity and energy requirements during the 2007 through 2011 period. The table set forth on the following page provides additional information on the historical operating performance of the GENCO facilities.

Historical GENCO Generation*
(GWH)

	Calendar Year				
Generating Facility	**2007**	**2008**	**2009**	**2010**	**2011**
Steam Turbine:					
E.F. Barrett 1,2	1,384	1,115	916	1,081	971
Far Rockaway 4	249	138	101	190	344
Glenwood 4,5	210	95	65	152	270
Northport 1-4	5,510	4,494	3,263	4,030	3,470
Port Jefferson 3,4	1,274	907	556	430	418
Total Steam Turbine	8,627	6,749	4,901	5,883	5,472
Combustion Turbine:					
E.F. Barrett 1-12	43	72	78	68	93
Wading River	100	93	45	65	35
East Hampton 1	16	20	13	13	8
Glenwood 1-3	3	2	1	2	1
Holtsville 1-10	84	59	46	75	42
Northport G-1	**	**	**	**	**
Port Jefferson GT	**	**	**	**	**
Shoreham 1-2	2	1	1	3	1
Southampton 1	3	6	2	3	2
Southhold 1	3	-	2	2	1
West Babylon 4	1	2	-	1	4
Total Combustion Turbine	255	255	188	231	187
Internal Combustion:					
East Hampton 2-4	3	3	2	2	1
Montauk 2-4	3	2	3	2	1
Total Internal Combustion	6	5	5	4	2
Total	8,888	7,009	5,094	6,117	5,662

* Source: National Grid Corporate Services.

** Less than 1.

The following table sets forth for each calendar year 2007 through 2011 the actual generation attributable to LIPA's 18% ownership interest in NMP2.

NMP2 Energy Generation

	2007	**2008**	**2009**	**2010**	**2011**
Energy (GWh)	1,636.0	1,536.1	1,785.6	1,591.0	1,707.1

The two tables below set forth: (i) contain a summary of existing power supply agreements (excluding the Power Supply Agreement with GENCO) and (ii) show for each calendar year 2007 through 2011 the energy output from such agreements.

Summary of Power Supply Agreements
(Excluding GENCO)

Unit Name	Capacity (MW)(1)	Contract Expiration	Unit Type (2)	Primary Fuel Type
NYPA Flynn	134.9	2020	CC	Natural Gas(3)
Suez Nassau Energy Combined Cycle	43.2	2016	CC/Cogen	Natural Gas(4)
Huntington Resource Recovery	24.4	2012	ST	Refuse
Babylon Resource Recovery	14.6	2013	ST	Refuse
Hempstead Resource Recovery	72.4	2034	ST	Refuse
Islip Resource Recovery	9.2	2035	ST	Refuse
Shoreham Energy	86.6	2017	SC	Kerosene(5)
National Grid Glenwood Landing	79.9	2027	SC	Natural Gas(5)
National Grid Port Jefferson	82.3	2027	SC	Natural Gas(5)
NextEra Bayswater	53.7	2020	SC	Natural Gas(5)
NextEra Jamaica Bay	54.3	2018	SC	Kerosene(5)
Global Common Greenport	52.0	2018	SC	Kerosene(5)
Equus	47.7	2017	SC	Natural Gas(4,5)
NYPA Power-for-Jobs	11.6	2012	N/A	N/A
Gilboa	50.0	2015	PS	Water
Village of Freeport	10.0	2034	SC	Natural Gas
Pinelawn Power	74.6	2025	CC	Natural Gas(4,5)
Calpine Bethpage 3	76.6	2025	CC	Natural Gas(5)
Bear Swamp Power	100.0(6)	2021	PS/Hydro	Water
Edgewood Energy	86.6	2018	SC	Natural Gas(5)
Caithness	309.6(7)	2029	CC	Natural Gas(4,5)
Brookfield	N/A(8)	2019	HY	Water
Fitzpatrick	124.4	2014	ST	Nuclear
PPL Energy Plus	N/A(8)	2019	IC	Landfill Methane
Marcus Hook	685.0(9)	2030	CC	Natural Gas
NYPA Hydro Sale for Resale	15.0	7	HY	Water
Long Island Solar Farm (LISF)	31.5	2031	PV	Solar
Eastern Long Island Solar Project (ELISP)	15.5(10)	(11)	PV	Solar

1 Summer capacity based upon summer 2011 DMNC test results.
2 CC = Combined Cycle; ST = Steam; Cogen = Cogeneration; IC = Internal Combustion; SC = Simple Cycle; PS = Pumped Storage; HY = Hydro; PV = Photovoltaic.
3 Also capable of burning No. 2 fuel oil.
4 Also capable of burning kerosene.
5 LIPA is responsible for fuel procurement and has contracted with a National Grid Sub for this service.
6 Reflects Unforced capacity (UCAP) stated in contract beginning June 2010.
7 LIPA agreement to purchase 286 MW of the total capacity.
8 Energy only contract.
9 Capacity only contract. No energy purchase.
10 Projected Capacity. Actual capacity from ELISP may be as low as 5.5 MW at Commercial Operation Date (COD) depending on how many of the solar facilities ultimately are constructed.
11 ELISP PPA expiration date will be 20 years from the COD of the project. Final ELISP COD is anticipated by the end of 2012.

Energy Output of Power Supply Agreements[1]
(GWH)

Type of Resource	Calendar Year 2007	2008	2009	2010	2011
Independent Power Producers					
NYPA Flynn	821.7	1,227.6	1,228.2	958.2	1,061.2
Other Power Supply Agreements	1,353.2	1,124.4	1,724.5	3,069.3	3,175.8
Other[2]	1,677.9	1,668.1	1,544.3	1,772.1	1,616.0
Subtotal IPPs	3,852.8	4,020.1	4,497.0	5,799.6	5,853.0
Entergy Fitzpatrick (off-Island)	1,169.7	1,100.4	1,237.1	1,067.8	1,225.2
Off-Island Purchases[3]	4,599.7	6,000.4	6,424.1	5,633.9	5,627.2
Other Purchases[4]	1,463.3	1,723.5	1,690.5	1,597.4	1,509.0
Total Purchases	11,085.5	12,844.4	13,848.7	14,098.7	14,214.4

1 Source: National Grid Corporate Services.
2 Includes energy produced by all other on-Island plants.
3 Energy purchases made on the spot market, net of sales on the spot market, plus bi-lateral purchases.
4 Reflects Power-for-Jobs and Long Island Choice programs.

Certain Additions to Power Supply Resources

LIPA has added significant power supply resources over the last decade. LIPA added in excess of 750 MW of newly constructed on-Island resources through agreements to purchase power from eight different owners of these newly constructed on-Island generating stations. In addition, LIPA has entered into an agreement with Neptune Regional Transmission System LLC to purchase 660 MW of firm transmission capacity over an undersea high voltage cable that has been installed between Sayreville, New Jersey and Levittown, New York. The cable, which became operational in 2007, permits LIPA to import 660 MW of power and related energy from the Pennsylvania, New Jersey and Maryland markets. LIPA has also entered into an agreement with FPL Marcus Hook for 685 MW of capacity from a combined-cycle plant in Pennsylvania beginning in 2010 to be provided over the Neptune Cable. LIPA has also entered into an agreement with Caithness Long Island LLC ("Caithness") to acquire 286 MW from a 326 MW combined-cycle plant which began full commercial operational in summer 2009. LIPA has also entered into an agreement with Long Island Solar Farm LLC (a BP Solar International Inc. affiliate) to purchase approximately 31.5 MW of power from an array of 164,312 photovoltaic solar panels located at Brookhaven National Laboratory, which began full commercial operation in November 2011. In addition, LIPA has entered into an agreement with Eastern Long Island Solar Project, LLC (an enXco Development Corporation affiliate) to purchase up to 15.5 MW of power from solar generating facilities under construction on Long Island that are expected to be fully operational by and the end of 2012. LIPA's Electric Resource Plan, which was updated in February 2010, concluded that based on LIPA's current probability weighted projections of Long Island's load and existing resources and planned resources, in addition to the successful implementation of its 10-year energy efficiency program, are projected to be sufficient to meet or exceed the Long Island minimum load requirements through 2020. Retirement of existing capacity could accelerate the need for capacity to meet the Long Island minimum requirement.

RATES AND CHARGES

The statute which created the Authority 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; payments in lieu of taxes; renewals, replacements and capital additions; the principal of and interest on any obligations issued pursuant to such resolution as the same become due and payable; and to establish or maintain any reserves or other funds or accounts required or established by or pursuant to the terms of such resolution.

Authority to Set Electric Rates

Under current State law, the Authority is empowered to set rates for electric service in the service area without being required by law to obtain the approval of the New York Public Service Commission ("PSC") or any other State regulatory body. However, the Authority agreed, in connection with the approval of the LIPA/LILCO Merger by the Public Authorities Control Board ("PACB") in 1997, that it would not impose any permanent increase, nor extend or reestablish any portion of a temporary rate increase, in average customer rates over a 12-month period in excess of 2.5% without approval of the PSC, following a full evidentiary hearing.

Legislation was passed by the New York State Legislature in June 2011 (the "2011 Legislation"), which amended the State Public Service Law to require the approval by the PSC of an increase in LIPA's average customer rates exceeding 2.5% over a 12-month period or to extend or reestablish any portion of a temporary rate increase exceeding 2.5%. Similar legislation has been proposed in the past, including in 2008 when the State Legislature at that time passed such legislation before it was vetoed on September 4, 2008 by former Governor Paterson and not enacted into law. Revised versions of the 2008 bill were introduced in 2009 and 2010 but were not enacted into law. As described below, the 2011 Legislation has been repealed.

Subsequent to the 2011 Legislation, a new bill requiring LIPA to undergo an audit of its management and operations was introduced and passed in both houses, and signed into law by Governor Cuomo on February 1, 2012 (the "2012 Legislation"). At the time the Governor signed the 2012 Legislation into law, the 2011 Legislation was repealed. It is not currently expected that a rate regulation bill will be proposed during this session, or at any point in the near future, based on public comments made by the bill sponsors of both the 2011 and 2012 Legislation; however, the Authority cannot predict with certainty that other similar legislation will not be introduced an acted upon at some point in the future.

The 2012 Legislation provides for the Department of Public Service to comprehensively and regularly audit the management and operations of the Authority. Such audit will entail review and evaluation of the Authority's overall operations and management, including the Authority's operations and management in the context of its duty to set rates at the lowest level consistent with standards and procedures provided for in the Act. The 2012 Legislation does not impact the Authority's ability to set rates for electric service in its service area without the approval of the PSC or any other State regulatory body.

Rate Tariffs and Adjustments

LIPA's base retail electric rates generally reflect traditional rate designs and include fixed customer charges for all customer classes, seasonal energy rates for all customer classes except street lighting, and seasonally differentiated demand charges for non-residential customer classes (greater than seven kW). Economic development and load retention incentives are provided to a small number of commercial customers. Miscellaneous service charges, pole attachment charges, and rental rates are also assessed on a monthly basis. In addition to the base delivery service charges, the Authority's charges include the FPPCA, a PILOT payments recovery rider, a rider providing for the recovery of the Suffolk Property Tax Settlement; an Energy Efficiency and Renewable Resource Charge to recover the costs of LIPA's customer-side programs and the New York State Assessment Charge to recover the newly-imposed cost of the Temporary State Energy and Utility Conservation Assessment (Public Service Law Section 18-a). Effective March 1, 2011, the Board of Trustees approved a 0.5% increase to the Energy Efficiency and Renewable Resource Charge. Effective March 1, 2011, the Board of Trustees approved an increase to the base rates for delivery service. The increase in the delivery service charge caused an average customer bill to increase approximately 1.9% to 2.2% overall for most rate classes. This was the first time since LIPA acquired the transmission and distribution system in 1998 and implemented the tariff that LIPA implemented an increase in its base rates for delivery service. Effective April 1, 2012, the Board of Trustees approved an increase to the base rates for delivery service, which caused an increase to the average residential customer's bill of approximately 1.8%.

LIPA's FPPCA provides for the recovery of fuel and purchased power costs in the period incurred, in amounts sufficient to allow the Authority to earn a financial target of $75 million with a variance of $50 million above or below such amount in each year. Should fuel and purchased power prices change such that LIPA would exceed or fail to meet its financial target, the FPPCA would be reduced or increased accordingly. In no event, however, can LIPA recover an amount that exceeds its fuel and purchased power costs incurred. Over the past few years, LIPA has regularly modified the FPPCA in response to changes in fuel and purchased power prices.

Change in Methodology to Estimate Unbilled Revenue

Effective January 2010, the Authority changed its accounting methodology used to estimate unbilled energy deliveries and the related customer receivables. Consistent with electric industry practice, LIPA bills its customer for lost energy. After LIPA acquired LILCO in 1998, it continued the accounting methodology for recording unbilled revenue that had been used by LILCO since 1991. When Authority staff found that the methodology being used was producing unexpected results and upon further investigation determined the methodology to be flawed, it engaged independent outside consultants who supported the staff's findings. That flawed methodology produced revenue requirements that were overestimated on an aggregate basis by $231 million since 1991, which represents approximately 0.45% of the total amount of electric sales revenue collected by LILCO and LIPA over that 20 year period. As a result, effective January 2010, the Authority changed its accounting methodology used to estimate unbilled energy deliveries and the related customer receivables. This change is needed to more accurately estimate power delivered to customers from the date of their last billing to the end of each accounting period. The unbilled revenue represents an estimate of customer usage during the period. This change in how unbilled revenue is estimated does not impact the total operating cash flows for any historical period. The change would have increased the unbilled revenues, accounts receivables and would have revised reported changes in net assets if it had been in effect prior to 2010. This change was adopted after an extensive analysis of the prior methodology. The prior methodology based the estimate of unbilled sales on several factors including electrical usage, seasonal factors, rate differentials and line losses. The Authority has determined that a more accurate and appropriate method is to accrue unbilled revenues by estimated unbilled consumption at the customer meter.

When this change was implemented effective January 2010, it resulted in (i) an increase of estimated unbilled receivables of approximately $231 million; (ii) the establishment of a regulatory liability of approximately $129 million to reflect the amount of revenue deferred that will be returned to the customers in accordance with the operation of the FPPCA; (iii) a $30 million decrease in the unamortized balance of the acquisition adjustment related to a reserve acquired from LILCO; and (iv) a $72 million increase in net assets.

PILOTs

The Act also requires the Authority to make payments in lieu of taxes, i.e., PILOTs, to municipalities and school districts equal to the property taxes that would have been received by each such jurisdiction from LILCO if the acquisition by the Authority had not occurred, and to make PILOTs for certain State taxes (including gross receipts taxes) and local taxes (including temporary transit station maintenance surcharges charged by the Metropolitan Transportation Authority of New York) which would otherwise have been imposed on LILCO. The PILOT payments recovery rider allows the Authority to recover PILOTs representing these gross receipts taxes and surcharges. All other PILOTs are recovered in the Authority's base rates or through the FPPCA, for certain PILOTs related to power generation stations under power supply agreements.

BILLING AND COLLECTIONS

At December 31, 2011, the Authority served approximately 1.1 million customers in its Service Area. For the 12-month periods ended, December 31, 2007, December 31, 2008, December 31, 2009 December 31, 2010 and December 31, 2011, the 12-month write-off rates for uncollectible accounts were 0.47%, 0.51%, 0.77% 0.71 %, and 0.68%, respectively.

LITIGATION

LIPA is involved in numerous actions arising from the ordinary conduct of its business both prior to and subsequent to the LIPA/LILCO Merger including environmental claims brought by governments and individual plaintiffs alleging that LIPA is responsible for all or a portion of the clean-up costs or personal injuries or damages as a result of the alleged use, release or deposit of hazardous substances, including asbestos. While LIPA cannot presently predict the costs of such pending claims, or additional similar claims which may arise in the future, LIPA believes that such litigation, in the aggregate, will not have a material adverse effect on the business or the affairs of the Authority or LIPA. See the Authority's Consolidated Financial

Statements for the years ended December 31, 2011 and 2010, Note 13 for a description of certain litigation in which LIPA is involved.

OTHER

The Authority and LIPA's offices are located at 333 Earle Ovington Blvd., Uniondale, New York 11553, phone (516) 222-7700, facsimile: (516) 222-9137 Attn: Chief Financial Officer.

Neither the Authority nor LIPA has failed, in any material respect, to timely make any required filing under the Continuing Disclosure Certificates.

This Annual Report contains statements which, to the extent they are not recitations of historical fact, constitute "forward-looking statements." In this respect, the words "estimate," "project," "anticipate," "expect," "intend," "believe," and similar expressions are intended to identify forward-looking statements. A number of important factors affecting the Authority's and LIPA's business and financial results could cause actual results to differ materially from those stated in the forward-looking statements.

Long Island Power Authority
and
Long Island Lighting Company d/b/a LIPA

By: Michael Taunton
Name: Michael J. Taunton
Title: Chief Financial Officer

DATE: June 5, 2012

APPENDIX A

List of CUSIP+ Numbers

Series	CUSIP	Maturity/ Mandatory Purchase	Coupon or Yield	Serial/Term
Electric System General Revenue Bonds				
Capital Appreciation Bonds				
1998A	542690BX9	12/1/2013	5.150%	CABs
1998A	542690BY7	12/1/2014	5.200%	CABs
1998A	542690BZ4	12/1/2015	5.250%	CABs
1998A	542690CA8	12/1/2016	5.250%	CABs
1998A	542690CB6	12/1/2017	5.280%	CABs
1998A	542690CC4	12/1/2018	5.280%	CABs
1998A	542690CD2	12/1/2019	5.280%	CABs
1998A	542690CE0	12/1/2020	5.300%	CABs
1998A	542690CF7	12/1/2021	5.300%	CABs
1998A	542690CG5	12/1/2022	5.300%	CABs
1998A	542690CH3	12/1/2023	5.300%	CABs
1998A	542690CJ9	12/1/2024	5.300%	CABs
1998A	542690CK6	12/1/2025	5.300%	CABs
1998A	542690CL4	12/1/2026	5.300%	CABs
1998A	542690CM2	12/1/2027	5.300%	CABs
1998A	542690CN0	12/1/2028	5.300%	CABs
Capital Appreciation Bonds				
2000A	542690NL2	6/1/2013	5.540%	CABs
2000A	542690NM0	6/1/2014	5.600%	CABs
2000A	542690NN8	6/1/2015	5.670%	CABs
2000A	542690NP3	6/1/2016	5.720%	CABs
2000A	542690NQ1	6/1/2017	5.770%	CABs
2000A	542690NR9	6/1/2018	5.810%	CABs
2000A	542690NS7	6/1/2019	5.830%	CABs
2000A	542690NT5	6/1/2020	5.860%	CABs
2000A	542690NU2	6/1/2021	5.880%	CABs
2000A	542690NV0	6/1/2022	5.900%	CABs
2000A	542690NW8	6/1/2023	5.910%	CABs
2000A	542690NX6	6/1/2024	5.920%	CABs
2000A	542690NY4	6/1/2025	5.930%	CABs
2000A	542690NZ1	6/1/2026	5.940%	CABs
2000A	542690PA4	6/1/2027	5.950%	CABs
2000A	542690PB2	6/1/2028	5.950%	CABs
2000A	542690PC0	6/1/2029	5.950%	CABs

Series	CUSIP	Maturity/ Mandatory Purchase	Coupon or Yield	Serial/Term
Current Interest Bonds				
2001A	542690QK1	9/1/2013	4.600%	Serial
2001A	542690QL9	9/1/2014	4.700%	Serial
2001A	542690QZ8	9/1/2027	5.000%	Term
2001A	542690QU9	9/1/2029	5.125%	Term
Current Interest Bonds				
2003B	542690TV4	12/1/2012	5.250%	Serial
2003B	542690TW2	6/1/2013	5.250%	Serial
2003B	542690TX0	12/1/2013	5.250%	Serial
2003B	542690TY8	6/1/2014	5.250%	Serial
2003B	542690TZ5	12/1/2014	5.250%	Serial
Current Interest Bonds				
2003C	542690UG5	9/1/2013	4.250%	Serial
2003C	542690UJ9	9/1/2014	4.375%	Serial
2003C	542690UL4	9/1/2015	4.500%	Serial
2003C	542690UN0	9/1/2016	4.500%	Serial
2003C	542690UP5	9/1/2016	5.000%	Serial
2003C	542690UU4	9/1/2021	5.000%	Serial
2003C	542690UW0	9/1/2022	5.000%	Serial
2003C	542690UX8	9/1/2023	5.000%	Serial
2003C	542690UH3	9/1/2024	5.000%	Serial
2003C	542690UZ3	9/1/2027	4.700%	Serial
2003C	542690VB5	9/1/2028	4.750%	Serial
2003C	542690VA7	9/1/2027	5.000%	Term
2003C	542690VC3	9/1/2028	5.000%	Term
2003C	542690UY6	9/1/2029	5.250%	Term
2003C	542690VD1	9/1/2033	5.000%	Term
2003I	542690L34	12/1/2029	Variable	Term
2003J	542690L67	12/1/2029	Variable	Term
2003L	542690L91	12/1/2029	Variable	Term
2003M	542690L83	12/1/2029	Variable	Term
2003N	542690L59	12/1/2029	Variable	Term
2003O	542690L42	12/1/2029	Variable	Term
Current Interest Bonds				
2004A	542690WP3	9/1/2013	3.800%	Serial
2004A	542690WQ1	9/1/2014	3.875%	Serial
2004A	542690WR9	9/1/2015	4.000%	Serial
2004A	542690WS7	9/1/2016	4.125%	Serial
2004A	542690WT5	9/1/2017	4.250%	Serial
2004A	542690WU2	9/1/2018	4.250%	Serial

Series	CUSIP	Maturity/ Mandatory Purchase	Coupon or Yield	Serial/Term
2004A	542690WV0	9/1/2019	4.375%	Serial
2004A	542690WW8	9/1/2020	4.500%	Serial
2004A	542690WX6	9/1/2021	4.500%	Serial
2004A	542690WY4	9/1/2022	4.625%	Serial
2004A	542690WZ1	9/1/2023	4.750%	Serial
2004A	542690XA5	9/1/2024	4.750%	Serial
2004A	542690XB3	9/1/2025	4.875%	Serial
2004A	542690XC1	9/1/2029	5.000%	Term
2004A	542690XD9	9/1/2029	5.100%	Term
2004A	542690XE7	9/1/2032	5.100%	Term
2004A	542690XF4	9/1/2034	5.000%	Term
Current Interest Bonds				
2006A	542690XP2	12/1/2016	4.000%	Serial
2006A	542690XQ0	12/1/2016	5.000%	Serial
2006A	542690XR8	12/1/2016	4.250%	Serial
2006A	542690XS6	12/1/2019	5.000%	Serial
2006A	542690XT4	12/1/2020	4.125%	Serial
2006A	542690XU1	12/1/2020	5.250%	Serial
2006A	542690XV9	12/1/2023	5.000%	Serial
2006A	542690XW7	12/1/2024	4.500%	Serial
2006A	542690XX5	12/1/2024	5.000%	Serial
2006A	542690XY3	12/1/2025	5.000%	Serial
2006A	542690XZ0	12/1/2026	4.250%	Serial
2006A	542690YA4	12/1/2026	5.000%	Serial
Current Interest Bonds				
2006B	542690YB2	12/1/2035	4.500%	Serial
2006B	542690YC0	12/1/2035	5.000%	Term
Current Interest Bonds				
2006C	542690ZA3	9/1/2035	5.000%	Term
Current Interest Bonds				
2006D	542690ZH8	9/1/2012	4.000%	Serial
2006D	542690ZJ4	9/1/2012	5.000%	Serial
2006D	542690ZK1	9/1/2013	4.000%	Serial
2006D	542690ZL9	9/1/2014	5.000%	Serial
2006D	542690ZM7	9/1/2014	4.125%	Serial
2006D	542690ZN5	9/1/2015	Variable	Serial
2006D	542690ZP0	9/1/2017	5.000%	Serial
2006D	542690ZQ8	9/1/2020	5.000%	Serial
2006D	542690ZR6	9/1/2021	5.000%	Serial
2006D	542690ZS4	9/1/2022	4.500%	Serial

Series	CUSIP	Maturity/ Mandatory Purchase	Coupon or Yield	Serial/Term
2006D	542690ZT2	9/1/2023	5.000%	Serial
2006D	542690ZU9	9/1/2025	5.000%	Serial
Current Interest Bonds				
2006E	542690A51	12/1/2017	5.000%	Serial
2006E	542690A44	12/1/2017	5.000%	Serial
2006E	542690A69	12/1/2018	5.000%	Serial
2006E	542690A85	12/1/2018	4.000%	Serial
2006E	542690A77	12/1/2018	5.000%	Serial
2006E	542690A93	12/1/2020	5.000%	Serial
2006E	542690B27	12/1/2021	5.000%	Serial
2006E	542690B35	12/1/2021	5.000%	Serial
2006E	542690B50	12/1/2022	5.000%	Serial
2006E	542690B68	12/1/2022	4.125%	Serial
2006E	542690B43	12/1/2022	5.000%	Serial
Current Interest Bonds				
2006F	542690C59	5/1/2013	5.000%	Serial
2006F	542690C67	5/1/2014	4.000%	Serial
2006F	542690C75	5/1/2015	4.000%	Serial
2006F	542690C83	5/1/2015	5.000%	Serial
2006F	542690C91	5/1/2016	4.000%	Serial
2006F	542690D25	5/1/2016	5.000%	Serial
2006F	542690D33	5/1/2017	5.000%	Serial
2006F	542690D41	5/1/2018	5.000%	Serial
2006F	542690D58	5/1/2019	5.000%	Serial
2006F	542690D66	5/1/2020	4.000%	Serial
2006F	542690D74	5/1/2021	4.000%	Serial
2006F	542690D90	5/1/2028	4.250%	Serial
2006F	542690D82	5/1/2028	4.500%	Serial
2006F	542690E24	5/1/2033	4.250%	Term
Current Interest Bonds				
2008A	542690N32	5/1/2033	5.500%	Term
2008A	542690N40	5/1/2033	6.000%	Term
Current Interest Bonds				
2008B	542690Q54	4/1/2019	5.250%	Serial
2008B	542690Q62	4/1/2020	5.375%	Serial
2008B	542690Q70	4/1/2021	5.500%	Serial
2008B	542690Q88	4/1/2022	5.500%	Serial
2008B	542690Q96	4/1/2023	5.625%	Serial
2008B	542690R20	4/1/2024	5.625%	Serial

Series	CUSIP	Maturity/ Mandatory Purchase	Coupon or Yield	Serial/Term
2008B	542690R38	4/1/2025	5.750%	Serial
2008B	542690R46	4/1/2033	5.750%	Term
Current Interest Bonds				
2009A	542690S52	4/1/2014	3.000%	Serial
2009A	542690S60	4/1/2015	5.000%	Serial
2009A	542690S78	4/1/2016	3.500%	Serial
2009A	542690S86	4/1/2017	5.000%	Serial
2009A	542690S94	4/1/2018	5.000%	Serial
2009A	542690T28	4/1/2019	5.000%	Serial
2009A	542690T36	4/1/2020	4.500%	Serial
2009A	542690T44	4/1/2020	5.250%	Serial
2009A	542690T51	4/1/2021	5.250%	Serial
2009A	542690T69	4/1/2022	5.500%	Serial
2009A	542690T77	4/1/2023	5.000%	Serial
2009A	542690T85	4/1/2024	5.500%	Serial
2009A	542690T93	4/1/2030	5.700%	Serial
2009A	542690U34	4/1/2039	5.750%	Serial
2009A	542690U26	4/1/2033	6.250%	Term
Current Interest Bonds				
2010A	542690V41	5/1/2014	3.000%	Serial
2010A	542690V66	5/1/2014	4.000%	Serial
2010A	542690V82	5/1/2014	5.000%	Serial
2010A	542690V58	5/1/2015	2.500%	Serial
2010A	542690V74	5/1/2015	3.000%	Serial
2010A	542690V90	5/1/2015	4.000%	Serial
2010A	542690W24	5/1/2015	5.000%	Serial
(Federally Taxable - Issuer Subsidy - Build America Bonds) Current Interest Bonds				
2010B	542690W32	5/1/2020	4.850%	Serial
2010B	542690W40	5/1/2021	5.100%	Serial
2010B	542690W57	5/1/2022	5.250%	Serial
2010B	542690W65	5/1/2024	5.450%	Serial
2010B	542690W73	5/1/2025	5.600%	Serial
2010B	542690W81	5/1/2026	5.700%	Serial
2010B	542690W99	5/1/2041	5.850%	Serial

Series		CUSIP	Maturity/ Mandatory Purchase	Coupon or Yield	Serial/Term
Current Interest Bonds					
2011A		542690X31	5/1/2016	5.000%	Serial
2011A		542690X49	5/1/2017	4.000%	Serial
2011A		542690X98	5/1/2017	5.000%	Serial
2011A		542690X56	5/1/2018	4.000%	Serial
2011A		542690Y22	5/1/2018	5.000%	Serial
2011A		542690X64	5/1/2019	5.000%	Serial
2011A		542690X72	5/1/2020	5.000%	Serial
2011A		542690X80	5/1/2021	5.000%	Serial
2011A		542690Y30	5/1/2036	5.000%	Serial
2011A		542690Y48	5/1/2038	5.000%	Term
NYSERDA Bonds					
P	1985A	649845ES9/ET7	3/1/2016	5.150%*	
P	1985B	649845CX0	3/1/2016	5.150%*	
P	1993B	649841BU6/DD2	11/1/2023	5.300%*	
P	1994A	649841BW2/DE0	10/1/2024	5.300%*	
P	1995A	649841BZ5	8/1/2025	5.300%*	

Note: P indicates Promissory Note Obligation by KeySpan

* indicates adjustable rate converted to fixed

\+ CUSIP numbers have been assigned by an organization not affiliated with the Authority and are included solely for the convenience of the holders of the Authority's bonds. The Authority is not responsible for the selection or uses of these CUSIP numbers, nor is any representation made as to the correctness of the CUSIP numbers as indicated in this Appendix A.

APPENDIX B

Audited Basic Financial Statements

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

Basic Financial Statements

December 31, 2011 and 2010

(With Independent Auditors' Report Thereon)

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

Basic Financial Statements

December 31, 2011 and 2010

Table of Contents

KPMG LLP
345 Park Avenue
New York, NY 10154

Independent Auditors' Report

The Board of Trustees
Long Island Power Authority:

We have audited the accompanying balance sheets of the Long Island Power Authority (Authority), a component unit of the State of New York, as of December 31, 2011 and 2010, and the related statements of revenues, expenses, and changes in net assets, and statements of cash flows, which collectively comprise the Authority's basic financial statements. These financial statements are the responsibility of the Authority's management. Our responsibility is to express an opinion on these 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 financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Authority's internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Authority as of December 31, 2011 and 2010, and the changes in its financial position and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

In accordance with *Government Auditing Standards*, we have also issued a report dated March 29, 2012, 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 and 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* and should be considered in assessing the results of our audit.

The accompanying management's discussion and analysis listed in the accompanying table of contents is not a required part of the basic financial statements but is supplementary information required by U.S. generally accepted accounting principles. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

KPMG LLP

March 29, 2012

KPMG LLP is a Delaware limited liability partnership,
the U.S. member firm of KPMG International Cooperative
("KPMG International"), a Swiss entity.

Overview of the Financial Statements

This report consists of three parts: management's discussion and analysis (unaudited), the basic financial statements, and the notes to the financial statements.

The financial statements provide summary information about the Authority's overall financial condition. The notes provide explanation and more details about the contents of the financial statements.

The Authority is considered a special-purpose government entity engaged in business-type activities and follows financial reporting for enterprise funds. The Authority's financial statements are prepared in accordance with generally accepted accounting principles (GAAP) as prescribed by the Governmental Accounting Standards Board (GASB). In accordance with GASB standards, the Authority has elected to comply with all authoritative pronouncements applicable to nongovernmental entities (i.e., pronouncements of the Financial Accounting Standards Board (FASB)) that do not conflict with GASB pronouncements.

Management's Discussion and Analysis (Unaudited)

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, 2011 and 2010. The discussion and analysis should be read in conjunction with the financial statements and accompanying notes, which follow this section. The Authority's financial statements are presented as an enterprise fund following the accrual basis of accounting. Under this basis, revenues are recognized in the period in which they are earned and expenses are recognized in the period in which they are incurred.

The Authority is also subject to the provisions of FASB ASC 980 *Regulated Operations*. This statement recognizes the economic impact of regulation, through the ratemaking process, to create future economic benefits and obligations affecting rate-regulated companies. Accordingly, the Authority records these future economic benefits and obligations as regulatory assets and regulatory liabilities, respectively.

GASB issued Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments* which was implemented by the Authority in 2010. This statement required state and local governments report the fair value of financial arrangements called "derivatives" or "derivative instruments" in their financial statements. This statement required retroactive application which resulted in reclassifications and adjustments to periods prior to 2010.

(Continued)

The following is a summary of the Authority's financial information for 2011, 2010, and 2009:

Balance Sheet Summary
(amounts in thousands)

		December 31,	
	2011	2010	2009
Assets:			
Current assets:			
Cash, cash equivalents and investments	$ 447,569	479,026	495,547
Other current assets	983,311	927,957	682,583
Regulatory assets	713,663	756,125	789,279
Noncurrent assets:			
Utility plant, net	6,624,802	6,431,896	6,459,718
Promissory notes receivable	155,425	155,425	155,425
Nonutility property and other investments	85,534	80,703	74,679
Deferred charges and long-term receivables	419,065	285,640	291,520
Acquisition adjustment, net	2,375,991	2,487,366	2,629,216
Total assets	$ 11,805,360	11,604,138	11,577,967
Liabilities and net assets:			
Regulatory liability	$ 137,693	277,308	164,520
Other current liabilities	1,367,921	1,213,524	1,168,720
Noncurrent liabilities:			
Long-term debt	6,379,609	6,363,244	6,394,949
Capital lease obligations	2,883,321	2,834,416	2,970,126
Other noncurrent liabilities	562,067	405,453	356,295
Deferred credits	78,779	133,024	203,637
Total liabilities	11,409,390	11,226,969	11,258,247
Net assets (deficit):			
Capital assets net of related debt	(96,610)	(87,016)	(171,412)
Restricted	30,676	365	46,340
Unrestricted	461,904	463,820	444,792
Total net assets	395,970	377,169	319,720
Total liabilities and net assets	$ 11,805,360	11,604,138	11,577,967

Summary of Revenues, Expenses, and Changes in Net Assets
(amounts in thousands)

		Year ended December 31,		
		2011	**2010**	**2009**
Electric revenue	$	3,684,596	3,853,052	3,312,160
Operating expenses:				
Operations – fuel and purchased power		1,743,533	1,879,839	1,566,005
Operations and maintenance		1,149,248	1,123,434	864,576
General and administrative		42,537	41,852	40,153
Depreciation and amortization		267,845	251,117	254,944
Payments in lieu of taxes		301,284	281,609	249,652
Total operating expenses		3,504,447	3,577,851	2,975,330
Operating income		180,149	275,201	336,830
Other income, net		35,389	46,445	33,519
Grant income		134,656	66,294	—
Interest charges		(331,393)	(330,491)	(331,899)
Change in net assets		18,801	57,449	38,450
Net assets – beginning of year		377,169	319,720	289,178
Cumulative effect of a change in accounting principle		—	—	(7,908)
Net assets – end of year	$	395,970	377,169	319,720

Excess of Revenues over Expenses

The revenues in excess of expenses for the years ended December 31, 2011, 2010 and 2009 totaled approximately $19 million, $57 million, and $38 million, respectively.

Revenues

Revenue for the twelve months ended December 31, 2011 decreased approximately $168 million when compared to 2010. Approximately $62 million of the variance was due to a one-time adjustment in 2010 resulting from a revised methodology for unbilled receivables. During 2011, LIPA realized lower sales resulting in lower revenue of $20 million and lower recoveries of power supply costs resulting from the reduction in the power supply rate which negatively impacted revenues by $147 million. This decrease was partially offset by increased (i) delivery charge rates positively impacting revenues by $39 million, (ii) Energy Efficiency Cost Recovery rates, which positively impacted revenues by $14 million (net of deferrals), (iii) late payment charges of $6 million; and, (iv) miscellaneous revenues of $2 million.

Revenue for the twelve months ended December 31, 2010 increased approximately $541 million when compared to 2009. This increase is primarily attributable to higher booked recoveries of power supply costs totaling $211 million (net of deferrals), the weather related effects which increased revenue by $113 million, higher average customer usage totaling approximately $32 million and an adjustment of $5 million related to a settlement of a long standing dispute with a commercial customer. In addition, effective January 1, 2010, the Authority implemented two new cost recovery mechanisms, the New York State Assessment and the Energy Efficiency Cost Recovery Rate, which increased revenues by $118 million. Also impacting revenue was the change in the method for unbilled receivables (discussed below) totaling $62 million.

Change in the method for unbilled receivables. Effective January 2010, the Authority changed its accounting methodology used to estimate unbilled energy deliveries and the related customer receivables. This new methodology estimates power delivered to customers from the date of their last billing to the end of the accounting period by estimating unbilled consumption at the customer's meter. The change resulted in: (i) an increase of estimated unbilled receivables of approximately $231 million; (ii) the establishment of a regulatory liability of approximately $129 million to reflect the amount of revenue deferred that will be returned to customers in accordance with the operation of the fuel and purchased power cost adjustment (FPPCA); (iii) a $30 million decrease in the unamortized balance of the acquisition adjustment related to a reserve acquired from LILCO; and (iv) a $72 million increase in net assets. The estimated unbilled revenue change did not impact reported total operating cash flows for any historical period.

The net impact of this change resulted in an increase of the 2010 net assets of approximately $72 million, $62 million of which resulted from the recognition of higher sales than previously estimated and approximately $10 million of which is due to reduced acquisition adjustment amortization related to a change to a reserve acquired from LILCO in 1998.

Fuel and Purchased Power Costs

The Authority's tariff includes a power supply costs recovery provision – the Fuel and Purchased Power Cost Adjustment (FPPCA) that provides for the amount and timing of fuel and purchased power cost recoveries.

For the year ended December 31, 2011, fuel and purchased power costs decreased $136 million. LIPA experienced lower commodity costs of $132 million, lower sales volumes impacting fuel costs by $11 million, lower amortization of prior year fuel deferrals totaling $1 million and partially offset by lower amortization of customer bill credits of $8 million.

For the year ended December 31, 2010, fuel and purchased power costs increased by $314 million. LIPA experienced higher commodity costs of $146 million, higher consumption due to sales volumes totaling $113 million, higher amortization of prior year fuel deferrals totaling $3 million and partially offset by lower amortization of customer bill credits of $52 million.

Operations and Maintenance Expense (O&M)

Operations and maintenance (O&M) expense for the year ended December 31, 2011, increased $26 million due primarily to higher storm restoration costs of $10 million, higher scheduled Power Supply Agreement (PSA) costs of $9 million, higher Management Services Agreement (MSA) costs of $4 million, higher Nine Mile Point 2 (NMP2) costs of $4 million, higher energy efficiency and renewable costs of $1 million partially offset by lower amortization of assessment costs of $2 million.

O&M expense for the year ended December 31, 2010, increased $259 million due primarily to higher storm restoration costs totaling $167 million (excluding FEMA reimbursements of $57 million for qualified storms which are included in Grant Income), higher energy efficiency and renewable costs of $15 million, higher NYS assessment charges of $45 million, higher Management Services Agreement (MSA) costs of $13 million (due to higher sales), and higher scheduled costs related to the PSA of $19 million.

General and Administrative Expenses (G&A)

General and administrative expenses for the year ended December 31, 2011, remained at a level similar to 2010.

General and administrative expenses for the year ended December 31, 2010, increased by $2 million primarily due to higher pension costs attributable to early retirement incentive provided in 2010.

Depreciation and Amortization

For the year ended December 31, 2011, depreciation and amortization increased approximately $17 million, due to the $10 million one-time adjustment recorded in 2010 to the acquisition adjustment associated with the unbilled methodology revision. The remaining $7 million increase was due to higher utility plant balances.

Depreciation and amortization for the year ended December 31, 2010, decreased by $4 million. The acquisition adjustment recorded from the LILCO acquisition in 1998 was decreased to reflect the true-up resulting from the unbilled revenue change discussed above. This decrease in the acquisition premium resulted in a reduction of the amortization expense of approximately $10 million. This decrease was partially offset by $6 million of increased depreciation expense as a result of higher utility plant balances.

Payments in Lieu of Taxes

For the year ended December 31, 2011, payments in lieu of taxes (PILOTs) increased approximately $20 million due to higher property taxes of $24 million on the transmission and distribution assets partially offset by lower revenue-based taxes of $4 million as a result of lower revenue.

For the year ended December 31, 2010, PILOTs increased approximately $32 million due to higher property taxes of $23 million on the transmission and distribution assets and higher revenue-based taxes (due to higher sales in 2010) of $9 million.

Other Income, Net

Other income decreased approximately $11 million compared to 2010 as a result of: (i) the recognition of $6 million of income related to previously deferred receipts that were deemed nonrefundable in 2010; (ii) lower earnings on the Authority's NMP2 trust account by $3 million and (iii) $2 million of non-operating expenses related to the Natural Resources Benefit contribution to fund the preservation of ecological properties as it relates to enhance the benefits of the Long Island Solar Farm Project at Brookhaven National Lab.

Other income increased approximately $13 million for the year ended December 31, 2010, when compared to 2009, as a result of: (i) higher earnings on the Authority's NMP2 trust account totaling $3 million partially offset by lower investment earnings of $1 million; (ii) the recognition of $6 million of income related to previously deferred receipts that were deemed nonrefundable; and, (iii) the absence of certain miscellaneous expenses totaling $5 million (due to the Board approved costs related to community benefits packages paid in 2009).

Grant Income

Grant income increased approximately $68 million compared to 2010 due primarily to the expected Federal Emergency Management Agency (FEMA) reimbursements related to Tropical Storm Irene. Long Island was declared an Emergency Disaster Area in August 2011 making LIPA eligible for federal aid. A claim for $116 million has been submitted to FEMA as of December 31, 2011. Management believes it is probable that FEMA will remit this amount.

Grant income increased approximately $66 million compared to 2009 resulting from (i) the FEMA reimbursement of $54 million for the eligible repair costs related to a March storm (ii) a $3 million FEMA reimbursement related to a 2009 storm event which was declared an Emergency Disaster Area in 2010, (iii) $3 million of interest subsidies related to the LIPA issued Electric System General Revenue Bonds, Series 2010B taxable Build America Bonds for which LIPA receives 35% of the interest paid on these Bonds from the federal government; and, (iv) a $6 million energy efficiency and renewable energy grant from New York State Energy Research Development Authority (NYSERDA) under its Regional Greenhouse Gas Initiative Program whereby LIPA participates in an agreement to reduce greenhouse gas emissions from its contracted power plants.

Interest Charges and Credits

For the year ended December 31, 2011, total interest charges increased by $1 million attributable to higher interest rates on its variable rate debt.

For the year ended December 31, 2010, total interest charges decreased by $1 million due to lower interest rates on variable rate debt and lower outstanding debt balances.

Cash, Cash Equivalents, and Investments and Liquidity

The Authority's cash, cash equivalents, and investments totaled approximately $448 million, $479 million, and $496 million at December 31, 2011, 2010, and 2009, respectively. The decrease from 2010 to 2011 is primarily due to lower revenues and timing of payments related to Tropical Storm Irene costs for which FEMA reimbursements are expected but have not been received as of December 31, 2011. The decrease from 2009 to 2010 is primarily due to debt maturities. The Authority also has the authorization to issue up to $300 million of commercial paper notes, $200 million of which were outstanding at December 31, 2011, 2010 and 2009.

Capital Assets

The Authority continued its investment in transmission and distribution (T&D) upgrades to manage reliability and to enhance capacity needed to meet anticipated customer demands. For the years ended December 31, 2011 and 2010, capital improvements to the T&D system totaled approximately $233 million and approximately $200 million, respectively. These improvements included interconnection equipment, the replacement or upgrade of transformer banks and circuit breakers, new substations, enhanced transmission lines and upgraded command and control equipment. During 2011, the Authority also invested approximately $26 million in Nine Mile Point 2 principally to support the power uprate (discussed in note 7), and approximately $7 million for information technology system improvements.

Regulatory Assets

Regulatory assets decreased approximately $42 million during the year ended December 31, 2011. The decrease is the result of: (i) the continued recovery of the 2003 deferred excess fuel and purchased power costs totaling approximately $37 million annually, scheduled to be recovered over a ten-year period which began January 1, 2004, in accordance with the Authority's tariff; (ii) the deferral of the New York State special assessment totaling $7 million; (iii) the scheduled recovery of approximately $38 million related to the Shoreham Property Tax Settlement Agreement through a surcharge on billings for electric service to customers residing in Suffolk County (the Shoreham surcharge), which began in 2003 (as discussed in greater detail in note 3 to the financial statements); and (iv) the amortization of certain deferred costs totaling $5 million. These decreases were partially offset by: (i) carrying charges of $30 million on the Shoreham Property Tax Settlement Agreement related credits for the year; (ii) the deferral of certain fuel and purchased power related costs totaling $15 million.

Regulatory assets decreased approximately $33 million during the year ended December 31, 2010. The decrease is the result of: (i) the continued recovery of the 2003 deferred excess fuel and purchased power costs totaling approximately $38 million annually, (ii) the deferral of the New York State special assessment totaling $9 million; (iii) the scheduled recovery of approximately $41 million related to the Shoreham surcharge; and (iv) the amortization of deferred interconnection facility costs totaling $2 million. These decreases were partially offset by: (i) carrying charges of $31 million on the Shoreham Property Tax Settlement Agreement related credits for the year; (ii) the deferral of certain fuel and purchased power related costs totaling $26 million.

Regulatory Liabilities

For the year ended December 31, 2011, the regulatory liabilities decreased by approximately $140 million resulting primarily from (i) return of the 2010 excess fuel and purchased power costs totaling $136 million; and, (ii) the return to customers approximately $57 million of the deferral resulting from the revised unbilled receivable estimate. These decreases were partially offset by: (i) the excess recovery of 2011 fuel and purchased power supply costs totaling $25 million which will be returned to customers through reductions in the FPPCA in 2012; and, (ii) the excess collection of the 2011 efficiency and renewable charge totaling $28 million.

For the year ended December 31, 2010, the regulatory liabilities increased by approximately $113 million resulting primarily from (i) the establishment of a regulatory liability totaling $129 million resulting from the revised unbilled receivable estimate; (ii) the excess recovery of fuel and purchased power supply costs totaling $136 million which will be returned to customers through reductions in the FPPCA in 2011; and (iii) the excess collection of the 2010 efficiency and renewable charge totaling $11 million. These increases were partially offset by the return of the 2009 excess recovery of fuel and purchased power supply costs totaling $163 million.

Debt

The Authority's debt, including current maturities, is comprised of the following instruments (amounts in thousands):

	Balance at December 31, 2011	2010	2009
General Revenue Bonds	$ 6,013,987	5,945,934	5,924,664
Subordinated Revenue Bonds	525,000	551,450	576,705
Commercial Paper Notes	200,000	200,000	200,000
NYSERDA Notes	155,420	155,420	155,420
	$ 6,894,407	6,852,804	6,856,789

During 2011, debt increased approximately $42 million resulting from: (i) the issuance of Electric System General Revenue Bonds Series 2011A totaling approximately $250 million (plus premium of approximately $12 million) which will be used to finance the Authority's on-going capital improvements program; and, (ii) the accretion of the capital appreciation bonds totaling approximately $30 million; partially offset by (iii) scheduled maturities of $238 million.

During 2010, debt decreased approximately $4 million resulting from scheduled maturities of approximately $225 million and the refunding of $212 million outstanding insured variable rate debt. This was partially offset by: (i) the issuance of Electric System General Revenue Bonds Series 2010A totaling approximately $193 million (plus premium of approximately $20 million) which was used to refund the $212 million variable rate debt; (ii) the issuance of the Electric System General Revenue Bonds Series 2010B totaling $210 million which will be used to finance the Authority's on-going capital improvements program; and (iii) the accretion of the capital appreciation bonds totaling approximately $30 million.

For a full discussion on the Authority's debt activities during 2011 and 2010, see note 9 to the financial statements.

Risk Management

The Authority is routinely exposed to commodity and interest rate risk. In order to attempt to mitigate such exposure, the Authority formed an Executive Risk Management Committee to strengthen executive management oversight for the risk mitigation activities of the Authority. In addition, the Authority retains an external consultant specializing in risk management, energy markets and energy trading to enhance the Authority's understanding of these areas.

The energy risk management program is intended to identify exposures to movements in fuel and purchased power prices, quantify the impact of these exposures on the Authority's financial position, liquidity and the fuel and purchased power costs and attempts to mitigate the exposures in line with the Authority's identified levels of risk tolerance. The Authority actively manages the program in both upward and downward trending markets and adjusts its positions as necessary in an attempt to mitigate the impact of potentially unfavorable market movements. At December 31, 2011, 2010 and 2009 the Authority had posted approximately $540,000, $365,000, and $46 million, respectively, of collateral to its counterparties in connection with its energy commodity hedge positions. No collateral was held by or posted by the Authority with respect to its interest rate derivatives.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, which is a new federal reform legislation signed into law on July 21, 2010, is currently being evaluated by the Authority to determine if the future regulations related to compliance requirements will have any potential impacts on the Authority's risk management programs.

In accordance with GASB Statement 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 and defers as unrealized gains and losses changes in fair value for investing derivatives consistent with FASB ASC 980 *Regulated Operations* and in accordance with its rate making practices. For a further discussion on these matters, see note 4 of the financial statements.

Fuel and purchased power transactions – For the year ended December 31, 2011, the Authority had realized losses of $89 million and recognized $2 million of option premium amortization which increased fuel and purchased power costs by $91 million. The Authority also recorded deferred outflows (unrealized loss) and deferred charges on commodity derivatives of approximately $141 million, reflecting the negative mark-to-market on the Authority's fuel derivative positions as of December 31, 2011.

For the year ended December 31, 2010, the Authority had realized losses of $169 million and recognized $5 million of option premium amortization which increased fuel and purchased power costs by $174 million. The Authority also recorded deferred outflows (unrealized loss) and deferred charges on commodity derivatives of approximately $123 million, reflecting the negative mark-to-market on the Authority's fuel derivative positions as of December 31, 2010.

Interest rate transactions – At December 31, 2011 and 2010, the Authority recorded deferred outflows of $56 million and $82 million, respectively, related to its interest rate hedging derivatives. The Authority also recorded net unrealized fair value losses on its investment derivatives of approximately $194 million and $43 million, respectively. Any gains or losses resulting from changes in the mark-to-market valuations on investment derivatives are deferred, and will be recognized when realized consistent with how LIPA recovers any such amounts in rates charged to customers.

Operating Agreements

Since 1998, the Authority has contracted with KeySpan Energy Corporation (KeySpan), a wholly owned subsidiary of National Grid plc, to provide the majority of services necessary to operate the Authority's transmission and distribution system under certain operating agreements. In anticipation of the expiration of these agreements, the Authority has undertaken competitive solicitations for such services, or negotiated extensions with National Grid.

Under the Management Services Agreement (MSA), which expires on December 31, 2013, KeySpan provides operations and management services related to the transmission and distribution system. The Authority conducted a competitive procurement seeking a vendor to provide the services currently provided under the MSA. In December 2011, the Board of Trustees approved the selection of Public Service Enterprise

Group (PSEG) as the new service provider to operate the Transmission & Distribution System for a scheduled term of ten years beginning January 1, 2014, which is subject to the appropriate regulatory approvals.

Under the Power Supply Agreement (PSA), which expires May 2013, KeySpan provides approximately 4,000 MW of capacity and related energy from the fossil fired generating plants of KeySpan. The Authority is currently evaluating a competitive solicitation for up to 2500 MW of capacity in anticipation of the expiration of the existing PSA, and is evaluating it existing options under the PSA which includes, among other things, a unilateral option to renew with KeySpan, for a 15 year term under substantially similar terms and conditions.

Under the Energy Management Agreement (EMA) and the Fuel Management and Bidding Services Agreement, which expire May 2013, KeySpan provides certain fuel management services for the generating facilities located on Long Island, including those owned by National Grid and others under contract with the Authority. As with the MSA and PSA, the Authority is currently evaluating its alternatives.

Certain other services, namely "mid-office" and "back-office" operations related to hedging activities related to physical fuel requirements are managed by two other providers through contracts that commenced on January 1, 2010 for a five-year period. These contracts are subject to an extension for a period of five years at the Authority's option.

Power Supply

The Authority has entered into numerous agreements for capacity and energy necessary to continue to satisfy the energy demand of our customers, while increasing the diversity of its fuel mix alternatives.

For additional information on power purchase agreements and its related accounting treatments, see notes 3 and 12 to the financial statements.

Investment Ratings

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

	Moody's (1)	**S&P (2)**	**Fitch (2)**
Senior Lien debt	A3	A-	A

(1) Negative outlook

(2) Stable outlook

Certain Senior and all Subordinated Lien debt and the Commercial Paper notes are supported by either a Letter of Credit (LOC) or are insured against default. Such debt carries the higher of the ratings of the credit support provider (LOC bank or insurance company), or that of the Authority.

Contacting the Long Island Power Authority

This financial report is designed to provide our 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 our website at www.lipower.org.

LONG ISLAND POWER AUTHORITY

(A Component Unit of the State of New York)

Balance Sheets

December 31, 2011 and 2010

(Amounts in thousands)

Assets and Deferred Outflows		2011	2010
Current assets and deferred outflows:			
Cash and cash equivalents	$	437,570	363,319
Investments		9,999	115,707
Counterparty collateral – posted by the Authority		540	365
Accounts receivable (net of allowance for doubtful accounts of $32,519, at December 31, 2011 and 2010)		527,871	565,339
Other receivables		202,866	80,639
Fuel inventory		165,280	167,630
Deferred charges		28,922	2,744
Deferred outflow – commodity derivatives		46,142	90,341
Regulatory assets due within one year:			
New York State assessment		12,079	9,260
Power Supply Management transition costs		3,183	3,183
Southampton visual benefit assessment		950	936
Shoreham property tax settlement		39,918	38,930
Fuel and purchased power costs recoverable		59,253	39,231
Material and supplies inventory		8,220	7,432
Prepayments and other current assets		3,470	13,467
Total current assets and deferred outflows		1,546,263	1,498,523
Noncurrent assets and deferred outflows:			
Utility plant and property and equipment, net		6,624,802	6,431,896
Promissory notes receivable – KeySpan Energy		155,425	155,425
Nonutility property and other investments		85,534	80,703
Other long term receivables		44,642	65,145
Deferred outflow – commodity derivatives		32,299	24,098
Deferred outflow – financial derivatives		56,178	81,729
Deferred charges		285,946	114,668
Regulatory assets:			
New York State assessment		9,260	18,528
Power Supply Management transition costs		6,367	9,551
Southampton visual benefit assessment		9,780	10,964
Shoreham property tax settlement		495,071	503,868
Fuel and purchased power costs recoverable		77,802	121,674
Acquisition adjustment (net of accumulated amortization of $1,689,045 and $1,577,670, respectively)		2,375,991	2,487,366
Total noncurrent assets and deferred outflows		10,259,097	10,105,615
Total assets and deferred outflows	$	11,805,360	11,604,138

See accompanying notes to basic financial statements.

Liabilities and Net Assets		2011	2010
Current liabilities:			
Short-term debt	$	200,000	200,000
Current maturities of long-term debt		278,025	238,100
Current portion of capital lease obligations		147,656	135,710
Accounts payable and accrued expenses		493,028	362,820
Regulatory liabilities:			
Fuel and purchased power costs refundable		62,713	192,115
Energy efficiency cost recovery variances		39,267	11,108
Commodity derivative instruments		75,064	93,086
Accrued payments in lieu of taxes		43,526	46,389
Accrued interest		55,103	53,616
Customer deposits		34,282	28,701
Claims and damages due within one year		41,237	55,102
Total current liabilities		1,469,901	1,416,747
Noncurrent liabilities:			
Long-term debt		6,379,609	6,363,244
Borrowings		105,315	110,297
Commodity derivative instruments		65,822	29,712
Financial derivative instruments		290,200	170,121
Regulatory liability – fuel and purchased power costs refundable		35,713	74,085
Capital lease obligations		2,883,321	2,834,416
Asset retirement obligation		79,457	73,675
Deferred credits		78,779	133,024
Claims and damages		21,273	21,648
Total noncurrent liabilities		9,939,489	9,810,222
Net assets (deficit):			
Invested in capital assets net of related debt		(96,610)	(87,016)
Restricted		30,676	365
Unrestricted		461,904	463,820
Total net assets		395,970	377,169
Total liabilities and net assets	$	11,805,360	11,604,138

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

Statements of Revenues, Expenses, and Changes in Net Assets

Years ended December 31, 2011 and 2010

(Amounts in thousands)

		2011	2010
Operating revenues – electric sales	$	3,684,596	3,853,052
Operating expenses:			
Operations – fuel and purchased power		1,743,533	1,879,839
Operations and maintenance		1,149,248	1,123,434
General and administrative		42,537	41,852
Depreciation and amortization		267,845	251,117
Payments in lieu of taxes		301,284	281,609
Total operating expenses		3,504,447	3,577,851
Operating income		180,149	275,201
Nonoperating revenues and expenses:			
Other income, net:			
Investing income		4,645	6,237
Grant income		134,656	66,294
Carrying charges on regulatory assets		30,829	31,576
Other		(85)	8,632
Total nonoperating revenues and expenses:		170,045	112,739
Interest charges and (credits):			
Interest on long-term debt, net		328,080	323,308
Other interest		10,901	14,116
Allowance for borrowed funds used during construction		(7,588)	(6,933)
Total interest charges		331,393	330,491
Total nonoperating revenues and expenses		(161,348)	(217,752)
Change in net assets		18,801	57,449
Total net assets, beginning of year		377,169	319,720
Total net assets, end of year	$	395,970	377,169

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, 2011 and 2010

(Amounts in thousands)

		2011	2010
Cash flows from operating activities:			
Received from customers for system sales, net of refunds	$	3,634,133	3,738,230
Other operating revenues received		59,130	55,136
Paid to suppliers and employees:			
Operations and maintenance		(1,093,663)	(1,113,622)
Fuel and purchased power		(1,711,081)	(1,841,547)
Payments in lieu of taxes		(401,676)	(389,049)
Collateral on fuel derivative transactions, net		(175)	45,975
Net cash provided by operating activities		486,668	495,123
Cash flows from investing activities:			
Sales of investment securities		223,808	344,204
Purchase of investment securities		(117,875)	(335,275)
Fair value adjustment – short term securities		16	(15)
Realized gains on short term securities		(242)	(338)
Earnings received on investments		597	1,134
Other		3,503	1,925
Net cash provided by (used in) investing activities		109,807	11,635
Cash flows from noncapital financing related activities:			
Grant proceeds		29,717	50,691
Net cash provided by noncapital related activities		29,717	50,691
Cash flows from capital and related financing activities:			
Capital and nuclear fuel expenditures		(265,738)	(248,912)
Proceeds from promissory note		8,075	8,075
Proceeds from the issuance of bonds, net of discount/premium		261,693	421,759
Bond issuance costs		(2,137)	(2,379)
Interest paid, net		(315,734)	(306,977)
Redemption of long-term debt		(238,100)	(436,960)
Net cash used in capital and related financing activities		(551,941)	(565,394)
Net increase (decrease) in cash and cash equivalents		74,251	(7,945)
Cash and cash equivalents at beginning of year		363,319	371,264
Cash and cash equivalents at end of year	$	437,570	363,319
Reconciliation to net cash provided by operating activities:			
Operating income	$	180,149	275,201
Adjustments to reconcile operating income to net cash provided by operating activities:			
Depreciation and amortization		267,845	251,117
Nuclear fuel burned		8,452	7,466
Shoreham surcharges		38,063	40,987
Provision for claims and damages		226,677	218,805
Accretion of asset retirement obligation		3,826	4,236
Amortization of settlement benefits to ratepayers		(39,475)	(48,000)
Other, net		(12,852)	(5,518)
Changes in operating assets and liabilities:			
Accounts receivable, net		42,669	(271,204)
Regulatory asset – New York State assessment		6,449	9,252
Fuel and material and supplies inventory		1,562	(10,757)
Fuel and purchased power costs adjustments		(140,781)	129,385
Counterparty collateral		(175)	45,975
Claims, damages and storm restoration		(240,917)	(180,921)
Accounts payable, accrued expenses and other		145,176	29,099
Net cash provided by operating activities	$	486,668	495,123

See accompanying notes to basic financial statements.

(1) Basis of Presentation

The Long Island Power Authority (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's reporting entity is comprised of itself and its operating subsidiary the Long Island Lighting Company (LILCO), a wholly owned subsidiary of the Authority doing business as LIPA. LIPA has one share of $1 par value common stock authorized, issued and outstanding, which is held by the Authority.

As the Authority holds 100% of the common stock of LIPA and controls the operations of LIPA, under Governmental Accounting Standard Board Statement (GASB) No. 14, *The Financial Reporting Entity*, LIPA is considered a blended component unit of the Authority and the assets, liabilities and results of operations are consolidated with the operation of the Authority for financial reporting purposes.

The Authority and its blended component unit, LIPA, are referred to collectively, as the "Authority" in the financial statements. All significant transactions between the Authority and LIPA have been eliminated.

(2) Nature of Operations

The Authority, as owner of the transmission and distribution system located in the New York State Counties of Nassau and Suffolk (with certain limited exceptions) and a small portion of Queens County known as the Rockaways (Service Area), is responsible for supplying electricity to customers within the Service Area. The Authority has contracted with KeySpan Energy Corporation (KeySpan), a wholly owned subsidiary of National Grid plc, to provide the majority of services necessary to operate the Authority's transmission and distribution system. The Authority pays KeySpan directly and KeySpan, in turn, pays the salaries of its employees and fees of its contractors and suppliers. In 2011 and 2010, the Authority paid to KeySpan approximately $2 billion each year under operating agreements, which includes all fees under such agreements, reimbursement for various taxes and PILOTS, certain fuel and purchased power costs, capital projects, conservation services, research and development and various other expenditures authorized by the Authority. In addition, the Authority contracts with two other service providers to manage certain fuel related services.

Below is a summary of the Operating Agreements with these service providers:

MSA. Under the Management Services Agreement (MSA), KeySpan provides operations and management services related to the transmission and distribution system. In 2006, the Authority amended the MSA and certain other Operating Agreements. The Amended and Restated MSA has a term that expires on December 31, 2013. In anticipation of the expiration of the Amended and Restated MSA on December 31, 2013, the Authority conducted a competitive procurement seeking a vendor to provide the services currently provided under the MSA. In December 2011, the Board of Trustees approved the selection of Public Service Enterprise Group (PSEG) as the new service provider to take over the operation of the Transmission & Distribution System beginning January 1, 2014 under a new Long Island based company (PSEG LI) that will focus exclusively on services to the Authority. In January 2012, the Authority and PSEG LI executed an Operations Services Agreement (OSA) for a scheduled term of ten years beginning January 1, 2014, which is subject to the appropriate regulatory approvals. In addition, the Authority and PSEG LI have executed a Transition Services Agreement (TSA) for a term of approximately two years that requires PSEG LI to perform a variety of specified activities in order to position itself to assume responsibility to provide operation services under the OSA on January 1, 2014.

PSA. Under the Power Supply Agreement (PSA), KeySpan provides capacity and energy from the fossil fired generating plants of KeySpan. Under the PSA the Authority has a right of first refusal to purchase, on substantially the same terms as offered, all (but not less than all) GENCO generating facilities which GENCO may decide to sell to a foreign or foreign-controlled entity during the term of the PSA (Right of First Refusal). The PSA has a term that expires on May 28, 2013. The Authority is currently evaluating a Request for Proposal (RFP) for up to 2500 MW of capacity in anticipation of the expiration of the existing PSA. In addition, the Authority is evaluating it existing options under the PSA which includes, among other things, a unilateral option to renew the PSA, with KeySpan, for a 15 year term under substantially similar terms and conditions.

EMA. Under the Energy Management Agreement and the Fuel Management and Bidding Services Agreement, KeySpan provides fuel management services for the generating facilities located on Long Island including those owned by National Grid and others under contract with the Authority. The existing services provided under these Agreements with KeySpan expire May 2013. As with the MSA and PSA, the Authority is currently evaluating its alternatives.

Certain other services, namely “mid-office” and “back-office” operations related to commodity hedging activities are managed by two other providers through contracts that commenced on January 1, 2010 for a five-year period. These contracts are subject to an extension for a period of five years at the Authority’s option.

(3) Summary of Significant Accounting Policies

(a) General

The Authority complies with all applicable pronouncements of the Governmental Accounting Standards Board (GASB). In accordance with GASB Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting*, the Authority complies with all authoritative pronouncements applicable to nongovernmental entities (i.e., pronouncements of the Financial Accounting Standards Board (FASB)) that do not conflict with GASB 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. Under this basis, revenues are recognized in the period in which they are earned and expenses are recognized in the period in which they are incurred.

(b) Accounting for the Effects of Rate Regulation

The Authority is subject to the provisions of FASB ASC 980 *Regulated Operations*. This statement recognizes the economic ability of regulators, through the ratemaking process, to create future economic benefits and obligations affecting rate-regulated companies. Accordingly, the Authority records these future economic benefits and obligations as regulatory assets or regulatory liabilities, respectively.

Regulatory assets represent probable future revenues associated with previously incurred costs that are expected to be recovered from customers. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be refunded to customers through the ratemaking process.

In order for a rate-regulated entity to continue to apply the provisions of FASB ASC 980 *Regulated Operations*, it must continue to meet the following three criteria: (i) the enterprise's rates for regulated services provided to its customers must be established by an independent third-party regulator or its own governing board empowered by a statute to establish rates that bind customers; (ii) the regulated rates must be designed to recover the specific enterprise's costs of providing the regulated services; and (iii) in view of the demand for the regulated services and the level of competition, it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers.

Based upon the Authority's evaluation of the three criteria discussed above in relation to its operations, and the effect of competition on its ability to recover its costs, the Authority believes that FASB ASC 980 *Regulated Operations* continues to apply.

The Authority regularly assesses whether regulatory assets and liabilities are probable of recovery or refund. If recovery or refund is not approved by the Board of Trustees, which sets rates charged to customers, or if it becomes no longer probable that these amounts will be realized or refunded they would need to be written-off and recognized in the current period results of operations. In addition the acquisition adjustment totaling approximately $2.4 billion would be evaluated for impairment.

(c) Cash and Cash Equivalents and Investments

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. Certain investments and cash and cash equivalents have been designated by the Authority's Board of Trustees to be used for specific purposes, including rate stabilization, debt service, and capital expenditures. Investments' carrying values are reported at fair market value. For a further discussion, see note 8.

(d) Counterparty Collateral

The Authority and its counterparties require collateral posting for mark-to-market valuations that exceed established credit limits. At December 31, 2011 and 2010, the Authority was required to post approximately $540,000 and $365,000, respectively, of collateral to various counterparties, which is recorded as a current asset and is considered a restricted net asset.

(e) 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, wire and meters) are accounted for on an average unit cost basis by year of installation. For a further discussion, see note 6.

Property and equipment represents leasehold improvements, office equipment and furniture and fixtures of the Authority.

(f) Fuel Inventory

Under the terms of the EMA and various Power Purchase Agreements, the Authority owns the fuel oil used in the generation of electricity at the facilities under contract to the Authority. 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.

(g) Material and Supplies Inventory

This represents the Authority's share of material and supplies inventory needed to support the operation of the Nine Mile Point 2 (NMP2) nuclear power station.

(h) Promissory Note Receivable

As part of the 1998 Merger, KeySpan issued promissory notes to the Authority of approximately $1.048 billion. As of December 31, 2011 and 2010, approximately $155 million remained outstanding. The fair market value of the note at December 31, 2011 and 2010 is approximately $156 million. The interest rates and timing of principal and interest payments on the promissory notes from KeySpan are identical to the terms of certain LILCO indebtedness assumed by the Authority in the merger. KeySpan is required to make principal and interest payments to the Authority thirty days prior to the corresponding payment due dates.

(i) Nonutility Property and Other Investments

The Authority's nonutility property and other investments consist primarily of the Nine Mile Point 2 Decommissioning Trust Funds (the Trusts). At December 31, 2011 and 2010, the value of the Trusts was approximately $85 million and $81 million, respectively.

(j) Other Receivables and Long-Term Receivables

The current portion of other receivables includes approximately $116 million for a claim submitted to the Federal Emergency Management Agency (FEMA) related to Tropical Storm Irene. As a result of this storm, which occurred in August 2011, Long Island was declared an Emergency Disaster Area making the Authority eligible for federal aid. Management believes it is probable that FEMA will remit this amount.

The long term portion of other receivables represents synergy savings credits due from National Grid resulting from their purchase of KeySpan, plus the net present value of a receivable related to the partial reimbursement of costs to construct the interconnection facilities related to the Neptune cable, which is to be paid to the Authority over a period of 20 years.

(k) Deferred Outflows

This represents the accumulated changes in the fair value of hedging derivative instruments. Under hedge accounting, the change in the fair value of a hedging derivative instrument is reported as a deferred inflow or deferred outflow on the Balance Sheets.

The change in fair value of investment derivative instruments are reported as deferred charges, as the Board has authorized the deferral of these unrealized gains and losses, and all such gains and losses are deferred until realized, which corresponds to the period they are recovered in rates.

(l) Deferred Charges

Deferred charges consists primarily of: (i) the balance of the investment derivative instruments; and, (ii) the unamortized balance of costs incurred to issue long-term debt which are amortized to interest expense over the life of the debt issuance to which they relate.

(m) Regulatory Assets

Shoreham Property Tax Settlement (Settlement)

In January 2000, the Authority reached an agreement with Suffolk County, Town of Brookhaven, Shoreham-Wading River Central School District, Wading River Fire District and 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. As required under the terms of the agreement, the Authority was required to issue $457.5 million of rebates and credits to customers over the 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 approximately $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 its cost of pre-funding certain rebates and credits.

As future rates will be established at a level sufficient to recover all such costs identified above, the Authority recorded a regulatory asset in accordance with FASB ASC 980 *Regulated Operations*. The balance of the Shoreham property tax settlement regulatory asset as of December 31, 2011 and 2010 was approximately $535 million and $543 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.

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) that will be recovered from certain customers of the Town over a period of a 20 year period that began in 2009.

New York State Temporary Energy and Utility Conservation Assessment

As a result an amendment to the Public Service Law effective April 1, 2009, LIPA is required to collect from all customers a special assessment which will be paid directly to the State for a five year period that began in 2009. As the Authority's rates did not include the recovery of this assessment until approved by the Board of Trustees effective January 1, 2010, the 2009 assessment has been deferred and will be collected ratably from customers over the next four years.

Power Supply Management transition costs

Deferred costs related to transition to two new service providers under the EMA have been classified as a regulatory asset as the Board of Trustees has approved collection of these costs be recovered over a five year period coincident with the contracts which commenced on January 1, 2010 and expire December 31, 2015.

Fuel and Purchased Power Costs Recoverable

The Authority's tariff includes a fuel recovery provision – the Fuel and Purchased Power Cost Adjustment (FPPCA) that provides for the recovery of fuel and purchased power costs in the period incurred. Should fuel and purchased power prices change such that Authority would exceed or fail to meet its Board approved financial target, the FPPCA would be reduced or increased accordingly. In no event, however, may Authority recover an amount that exceeds its fuel and purchased power costs incurred.

Prior to 2004, the Authority deferred a portion of its excess fuel and purchased power costs and collected those costs in subsequent years. In order to transition to the current period recovery method, the Authority deferred, in 2003, approximately $365 million of unrecovered fuel and purchased power costs to be recovered over a 10-year period beginning January 1, 2004. As of December 31, 2011 and 2010, the uncollected balance of these items totaled approximately $73 million and $110 million, respectively.

Also recorded as fuel and purchased power costs recoverable are: (i) amounts incurred related to various energy projects, whose amortization is charged to fuel and purchased power costs over the period of benefit (the life of the power purchase agreement) totaling approximately $44 million and $41 million as of December 31, 2011 and 2010, respectively and (ii) excess credits related to prior year excess fuel and purchased power costs refunded to be recovered through rates in 2012 totaling approximately $19 million and $10 million as of December 31, 2011 and 2010, respectively.

(n) 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 using a 35-year life through 2033.

(o) 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 in accordance with FASB ASC 840 *Leases*. 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 balance sheet properly reflects 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 12.

(p) Deferred Credits

Deferred credits primarily represent amounts received from KeySpan/National Grid (Grid benefits) as a result of certain renegotiated agreements. The Board authorized $39 million and $48 million of these Grid benefits to be used during 2011 and 2010, respectively, as a reduction to the amounts recoverable from customers through the FPPCA. Also included in deferred credits is the Authority's unfunded other post-employment benefit obligation.

(q) 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).

(r) Commodity and Financial Derivative Instruments

Represents the amount that the Authority believes it would be required to pay in order to terminate these derivative instruments as of December 31, 2011 and 2010 which approximates fair value.

(s) Claims and Damages

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

(t) 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. Effective January 1, 2010, the Authority changed its methodology for the accrual of revenues. The prior methodology based the estimate of unbilled sales on several factors including electrical usage, seasonal factors, rate differentials and line losses. The Authority's revised method accrues unbilled revenues by estimating unbilled consumption at the customer meter.

All other revenue is reported as nonoperating revenue when service is rendered. Fuel and purchased power supply costs recoveries collected in excess of that incurred are deferred until the FPPCA rate is adjusted. For the years ended December 31, 2011, the Authority received approximately 54% of its revenues from residential sales, 44% from sales to commercial and industrial customers, and the balance from sales to public authorities and municipalities.

(u) Depreciation and Amortization

The provisions for depreciation for utility plant result from the application of straight-line rates by groups of depreciable properties in service assets. The rates are determined by age-life studies performed on depreciable properties. The average composite depreciation rate is 2.88% and 2.85% for December 31, 2011 and 2010, 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 is being depreciated over its estimated useful life using the straight-line method.

The following estimated useful lives and capitalization thresholds are used for utility property:

Category	Useful life
Generation – nuclear	39 – 46 years
Transmission and distribution	20 – 48 years
Common	4 – 41 years
Nuclear fuel in process and in reactor	6 years
Generation assets under capital lease	10 – 25 years

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

The Authority makes payments-in-lieu-of-taxes (PILOTS) for certain operating 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.

(w) 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 not an item of current cash income. 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 5.01% and 5.09% for the years ended December 31, 2011 and 2010, respectively.

(x) Income Taxes

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

(y) Regulatory Liability – Fuel and Purchased Power Costs Refundable

Regulatory liabilities represent amounts that are expected to be refunded to customers through the ratemaking process. In accordance with the FPPCA, the Authority must return any FPPCA revenues it recovers in excess of the fuel and purchased power costs it incurs. Any such over recoveries are recognized as regulatory liabilities. For 2011 and 2010, a regulatory liability resulting from such over recoveries totaled $25 million and $136 million, respectively. Such amounts are reflected as reductions in the FPPCA rate in the following year to return any excess recovery to the customers.

In 2010, as a result of the change in the unbilled revenue estimate, a regulatory liability for approximately $129 million was recorded that represents deferred revenue that will be refunded to customers. The Authority returned approximately $57 million in 2011 and will return the remaining excess recovery to customers as follows: $36 million in 2012 and in 2013.

(z) Asset Retirement Obligation

The Authority follows FASB ASC 410 *Asset Retirement and Environment Obligations* (ARO). An ARO exists when there is a legal obligation associated with the retirement of a tangible long-lived asset that results from the acquisition, construction, or development and/or normal operation of the asset. The Authority, as an 18% owner of Nine Mile Point 2 (NMP2) Nuclear Power Station, has a legal obligation associated with its retirement. This initial obligation is offset by the capitalization of the asset which is included in "Utility plant and property and equipment". As of December 31, 2011 and 2010, the NMP2 asset retirement obligation totaled approximately \$73 million and \$67 million, respectively. 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 deferred as a component of the ARO in accordance with FASB ASC 980 *Regulated Operations* and have no impact to the Authority's net assets. For a further discussion on the Authority's NMP2 decommissioning obligations and related funding see note 7.

Additionally, FASB ASC 410 *Asset Retirement and Environment Obligations* defines the term conditional asset retirement obligation as a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. As of December 31, 2011 and 2010, the asset retirement obligation for the Authority's transmission and distribution utility assets totaled approximately \$7 million.

A summary of the asset retirement obligation activity of the Authority for the years ended December 31, 2011 and 2010 is included below (amount in thousands):

		2011	2010
Asset retirement obligation:			
Beginning balance	$	73,675	73,680
Changes in fair market value of decommissioning fund		1,695	729
Change in estimate		—	(5,063)
Accretion expense		4,087	4,329
Balance at December 31,	$	79,457	73,675

(aa) 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 is measured using one of three approaches that best reflects the decline in service utility. Assets to be disposed of and assets held for sale are reported at the lower of the carrying amount or fair value less costs to sell.

(bb) Use of 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.

(cc) Reclassifications

Certain prior year amounts have been reclassified in the financial statements to conform to the current year presentation. Deferred costs related to transition to two new service providers have been reclassified as a regulatory asset as the Board of Trustees has approved collection of these costs be recovered over a five year period. In addition, the energy efficiency cost recovery variance deferrals have been reclassed to revenue in accordance with FASB ASC 980 *Regulated Operations.*

(dd) Recent Accounting Pronouncements

In December 2009, GASB issued Statement No. 57, *OPEB Measurements by Agent Employers and Agent Multiple – Employer Plans* (GASB No. 57). GASB No. 57 addresses issues related to the use of alternative measurement method and the frequency and timing of measurements by employers that participate in agent multiple-employer OPEB plans. The statement amends previous GASB statements on OPEB plans, and will improve the consistency of reporting for OPEB plans. This statement is effective for the Authority beginning in 2012. The Authority does not believe this statement will have a material impact on its financial statements.

In December 2010, GASB issued Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in the Pre-November 30, 1989 FASB and AICPA Pronouncements* (GASB No. 62). GASB No. 62 incorporates into GASB's authoritative literature certain accounting and financial reporting guidance issued on or before November 30, 1989 included in: FASB Statements and Interpretations, Accounting Principles Board Opinions, and Accounting Research Bulletins of the AICPA Committee on Accounting Procedure that do not conflict with or contradict GASB pronouncements. The statement also supersedes Statement No. 20*, Accounting and Financial Reporting for Proprietary Fund Accounting* which eliminates the election for business-type activities to apply post November 30, 1989 FASB Statements and Interpretations that do not conflict with GASB pronouncements. This statement becomes effective 2012. The Authority does not believe this statement will have a material impact on its financial statements.

In June 2011, GASB issued Statement No. 63, *Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position* (GASB No. 63). GASB No. 63 requires that deferred outflows of resources be reported in the statement of financial position in a separate section following assets and deferred inflows of resources be reported in a separate section following liabilities. GASB No. 63 becomes effective for periods beginning after December 15, 2011. The Authority does not believe this statement will have a material impact on its financial statements.

In June 2011, GASB issued Statement No. 64, *Derivative Instruments: Application of Hedge Accounting Termination Provisions – an amendment of GASB Statement No. 53* (GASB No. 64). GASB No. 64 is a clarification of whether an effective hedging relationship continues after the replacement of a swap counterparty or a swap counterparty's credit support provider. GASB No. 64 becomes effective for periods beginning after June 15, 2011. The Authority does not believe this statement will have a material impact on its financial statements.

(4) Derivative Instruments

The Authority uses derivative instruments to attempt to manage the cash flow impact of interest rate changes and market price fluctuations for the purchase of fuel oil, natural gas and electricity on its customers, net assets and cash flows. 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 Balance Sheets as 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 reported as a deferred inflow or deferred outflow on the Balance Sheets until the contract is settled or hedge accounting is terminated. The Authority's derivative instruments that do not meet the definition of a hedging derivative instrument 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 FASB ASC 980 *Regulated Operations* and 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 Assets 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 Assets in the period incurred.

A portion of the Authority's fuel and purchased power derivative contracts are exchange-traded contracts with readily available quoted market prices. Another portion is non exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter, on-line exchanges. The remainder of the fuel and purchased power as well as the financial derivative products represents contracts for which external sources or observable market quotes are not available. These contracts are valued based on various valuation techniques including but not limited to models internal to the Authority's energy risk management consultant based on extrapolation of observable market data with similar characteristics. Contracts valued with prices provided by models and other valuation techniques make up a significant portion of the total fair value of such derivative contracts. The Authority's policy is to not discount the fair value of each contract using an interest rate which represents default risk associated with a particular counterparty.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, which is a new federal reform legislation signed into law on July 21, 2010, is currently being evaluated by the Authority to determine if the future regulations related to compliance requirements will have any potential impacts on the Authority's risk management programs.

The Authority's derivative instruments at December 31, 2011 are as follows (in thousands):

Derivative instrument description		Fair value December 31, 2011	Net change in fair value	Fair value December 31, 2010	Type of hedge	Financial statement classification for changes in fair value
Hedging derivative instruments:						
Financial derivatives:						
Interest Rate Swap 1	$	(40,067)	(12,098)	(27,969)	Cash flow	Deferred outflow
Interest Rate Swap 2		(26,831)	(9,333)	(17,498)	Cash flow	Deferred outflow
Interest Rate Swap 3		—	81,957	(81,957)	Cash flow	Deferred outflow
Interest Rate Swap 7		(7,097)	(667)	(6,430)	Cash flow	Deferred outflow
Total	$	(73,995)	59,859	(133,854)		
Commodity derivatives:						
Natural Gas Swaps	$	(121,038)	(27,132)	(93,906)	Cash flow	Deferred outflow
Residual Oil Swaps		9,668	21,316	(11,648)	Cash flow	Deferred outflow
Purchased Power Swaps		36,404	47,337	(10,933)	Cash flow	Deferred outflow
Natural Gas Basis Swaps		(3,423)	(6,946)	3,523	Cash flow	Deferred outflow
Residual Oil Options		—	535	(535)	Cash flow	Deferred outflow
Natural Gas Options		(52)	888	(940)	Cash flow	Deferred outflow
Total	$	(78,441)	35,998	(114,439)		
Investment derivative instruments:						
Financial derivatives:						
Interest Rate Swap 3	$	(172,821)	(172,821)	—	N/A	Deferred charges
Interest Rate Swap 4		(21,692)	(3,559)	(18,133)	N/A	Deferred charges
Interest Rate Swap 5		(10,846)	(1,779)	(9,067)	N/A	Deferred charges
Interest Rate Swap 6		(10,846)	(1,779)	(9,067)	N/A	Deferred charges
Total	$	(216,205)	(179,938)	(36,267)		
Commodity derivatives:						
Natural Gas Options	$	(575)	(556)	(19)	N/A	Deferred charges
Natural Gas Swaps		(61,870)	(53,530)	(8,340)	N/A	Deferred charges
Total	$	(62,445)	(54,086)	(8,359)		

The terms of the Authority's commodity derivative instruments that were outstanding at December 31, 2011 and 2010 are summarized in the tables below:

	Notional amount ('000s)	Beginning date	Ending date	Authority pays per unit	Authority receives
2011:					
Natural Gas Swaps	117,025 Dths	1/1/2012	12/1/2014	$ 4.25 to 8.49	Natural Gas at Henry Hub
Residual Oil Swaps	382 Bbls	1/1/2012	8/1/2014	65.75 to 103.5	Residual Fuel Oil at NY Harbor
Purchased Power Swaps	6,087 Mwhs	1/1/2012	11/1/2014	37.88 to 81.40	Power at PJM East
Natural Gas Basis Swaps	3,083 Dths	1/1/2012	3/1/2012	0.94 to 4.86	Gas Basis between Henry Hub & Transco Z6, NY

	Notional amount ('000s)	Beginning date	Ending date	Authority pays per unit	Authority receives
2010:					
Natural Gas Swaps	62,168 Dths	1/1/2011	12/31/2013	$ 5.06 to 11.06	Natural Gas at Henry Hub
Residual Oil Swaps	1,772 Bbls	1/1/2011	7/31/2013	63.5 to 122.8	Residual Fuel Oil at NY Harbor
Purchased Power Swaps	1,906 Mwhs	1/1/2011	9/30/2013	60.5 to 144	Power at PJM East
Natural Gas Basis Swaps	3,393 Dths	1/1/2011	3/1/2011	0.57 to 3.25	Gas Basis between Henry Hub & Transco Z6, NY
Residual Oil Options	30 Bbls	1/1/2011	2/28/2011	94.35 to 100.35	Residual Fuel Oil at NY Harbor
Natural Gas Options	768 Dths	1/1/2011	10/31/2012	5.85 to 9.5	Natural Gas at Henry Hub

The terms of the Authority's financial derivative instruments that were outstanding at December 31, 2011 are summarized in the tables below (amounts in thousands):

Financial derivative	Type	Effecitve date	Termination date	Authority pays	Authority receives	Orignal notional	Upfront cash payment
Interest rate:							
Swap 1	Synthetic Fixed	11/12/1998	4/1/2025	4.208%	SIFMA	$ 150,000	$ —
Swap 2	Synthetic Fixed	11/12/1998	4/1/2025	4.208	SIFMA	100,000	—
Swap 3	Synthetic Fixed	6/1/2003	12/1/2029	5.120	69.47% of 1-month LIBOR	587,225	106,400
Swap 4	Basis Swap	7/1/2004	8/15/2033	SIFMA	70.50% of 1-month LIBOR	502,090	17,500
Swap 5	Basis Swap	7/1/2004	8/15/2033	SIFMA	70.50% of 1-month LIBOR	251,045	8,750
Swap 6	Basis Swap	7/1/2004	8/15/2033	SIFMA	70.50% of 1-month LIBOR	251,045	8,750
Swap 7	Synthetic Fixed	7/11/2006	9/1/2015	4.110%	CPI + 0.765%	110,715	—

Swap termination: In accordance with GASB No. 53, at the time of a termination event related to a current refunding of hedged debt, the balance of the amounts in deferred outflows are to be included in the net carrying amount of the refunded debt for the purposes of calculating the deferred loss on refunding. The portions of the debt associated with Swap 1, 2 and 3 had a current refunding resulting in a reassignment of the interest rate swaps to a new underlying notional debt with identical terms. This refunding and reassignment effectively terminated the original hedges. As a result, approximately $45 million of the deferred outflow at the refunding dates was apportioned to the deferred loss on refunding in 2010.

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 and no longer meeting the objective of the hedge. As long as the Authority fulfills its obligations under the contracts and does not default under the agreements, 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 value.

Basis Risk: The Authority is exposed to basis risk on certain of its pay-fixed interest rate swaps because the variable-rate payments received by the Authority (SIFMA, 69.47% of LIBOR) on these hedging derivative instruments are based upon indexes other than the actual interest rates the Authority pays on its hedged variable rate debt. The terms of the related hedging fixed 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 (i.e. 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 gate). If the correlation between these market prices should fail, the Authority may incur costs as a result of the hedging derivative instrument's inability to offset the price of the related commodity.

Rollover risk: The Authority is exposed to rollover risk on its Swap 1 and 2. Certain Series 2001 2A, 3A and 3B bonds mature in 2030 while Swap 1 and 2 terminate in April 2025, leaving the Authority exposed to interest rate volatility during the period from 2025 to 2030.

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 posted collateral under its interest rate derivative instruments.

The Authority has collateral requirements for all of its commodity derivatives. 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. At December 31, 2011 and 2010, the Authority had posted collateral with counterparties of approximately $0.5 million and $0.4 million, respectively.

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

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. Below is a table with the credit-ratings of the Authority's counterparties as of December 31, 2011 (amounts in millions):

Counterparty	Moody's	S&P	Authority's unsecured line of credit
Interest Rate Derivative Instruments			
Bank of America Corp	A2	A	$ —
Bear Stearns Capital Markets Inc.	Aa3	A	—
Citibank, N.A. New York	A1	A+	—
Lehman Brothers Financial Products Inc.	Not rated	Not rated	—
Merrill Lynch Capital Services	Baa1	A-	—
UBS AG, Stamford Branch	Aa3	A	—
Societe Generale	A1	A+	—
Morgan Stanley Capital Group Inc.	A2	A-	—
Commmodity Derivative Instruments			
Barclays Bank PLC	Aa3	A+	50
BP Corporation North America Inc.	Baa1	A	15
Credit Suisse Energy LLC	Aa1	A+	30
Deutsche Bank AG	Aa3	A+	75
J. Aron & Company	A1	A-	40
JPMorgan Chase Bank, N.A.	Aa1	A+	35
Macquarie Energy LLC	A1	A	10
Merrill Lynch Commodities, Inc.	Baa1	A-	20
Morgan Stanley Capital Group Inc.	A2	A-	80
Societe Generale	A1	A+	25

(5) Rate Matters

Under current New York State law, the Board of Trustees of the Authority is empowered to set rates for electric service in the Service Area without the approval of the New York State Public Service Commission (PSC) or any other state regulatory body. However, in connection with the approval of the 1998 merger of the Authority and LILCO (d/b/a LIPA) by the New York State Public Authorities Control Board (the PACB), the Authority agreed that it would comply with the condition imposed by the PACB and not impose any permanent increase, nor extend or re-establish any portion of a temporary rate increase, in average customer rates over a 12-month period in excess of 2.5% without approval of the PSC, following a full evidentiary hearing.

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; 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.

In addition to the delivery rate, the Authority's tariff also includes: (i) the FPPCA, 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, which allows for rate adjustments to accommodate changes in PILOTS; (iii) a rider providing for the recovery of costs associated with the Shoreham Property Tax Settlement; (iv) a rider for the Authority's energy efficiency and renewable program; and (v) a rider providing for the collection of the Temporary State Assessment imposed by the New York State Legislature.

As part of its ratemaking jurisdiction, and due to rising costs, the Authority proposed an increase to its delivery rates as part of the 2012 budget proposal. The Authority proposed an increase of approximately 1.5% across all rate classes to increase its recovery of operating expenses and property taxes (among other things). The Authority's Trustees approved the budget in December 2011 and, following public notice and hearings, approved the rate increase March 1, 2012, to be effective on March 5, 2012.

For a further discussion on rate matters, see note 13.

(6) Utility Plant and Property and Equipment

The following schedule summarizes the utility plant and property and equipment of the Authority as of December 31, 2011 (amounts in thousands):

	Beginning balance	Additions	Deletions	Ending balance
Capital assets, not being depreciated:				
Land	$ 17,566	—	—	17,566
Retirement work in progress	35,053	16,944	20,488	31,509
Construction in progress	168,412	269,685	182,584	255,513
Total capital assets not being depreciated	221,031	286,629	203,072	304,588
Capital assets, being depreciated:				
Generation – nuclear	704,310	1,723	134	705,899
Transmission and distribution	3,506,610	159,509	15,459	3,650,660
Common	39,802	4,516	791	43,527
Nuclear fuel in process and in reactor	96,325	26,332	—	122,657
Office equipment, furniture, and leasehold improvements	11,817	4,881	149	16,549
Generation and transmission assets under capital lease	3,555,024	196,325	—	3,751,349
Total capital assets being depreciated	7,913,888	393,286	16,533	8,290,641
Less accumulated depreciation for:				
Generation – nuclear	264,812	21,696	113	286,395
Transmission and distribution	757,146	128,081	32,832	852,395
Common	16,446	4,328	46	20,728
Nuclear fuel in process and in reactor	74,239	8,452	—	82,691
Office equipment, furniture, and leasehold improvements	5,482	3,052	688	7,846
Generation assets under capital lease	584,898	135,474	—	720,372
Total accumulated depreciation	1,703,023	301,083	33,679	1,970,427
Net value of capital assets, being depreciated	6,210,865	92,203	(17,146)	6,320,214
Net value of all capital assets	$ 6,431,896	378,832	185,926	6,624,802

In 2011, depreciation expense related to capital assets was approximately $157 million.

The following schedule summarizes the utility plant and property and equipment of the Authority as of December 31, 2010 (amounts in thousands):

		Beginning balance	Additions	Deletions	Ending balance
Capital assets, not being depreciated:					
Land	$	16,693	873	—	17,566
Retirement work in progress		35,940	17,964	18,851	35,053
Construction in progress		189,098	252,378	273,064	168,412
Total capital assets not being depreciated		241,731	271,215	291,915	221,031
Capital assets, being depreciated:					
Generation – nuclear		708,078	9,136	12,904	704,310
Transmission and distribution		3,284,051	252,869	30,310	3,506,610
Common		37,194	2,806	198	39,802
Nuclear fuel in process and in reactor		93,791	2,984	450	96,325
Office equipment, furniture, and leasehold improvements		5,280	12,579	6,042	11,817
Generation and transmission assets under capital lease		3,555,024	—	—	3,555,024
Total capital assets being depreciated		7,683,418	280,374	49,904	7,913,888
Less accumulated depreciation for:					
Generation – nuclear		250,926	21,817	7,931	264,812
Transmission and distribution		674,156	122,565	39,575	757,146
Common		12,684	3,924	162	16,446
Nuclear fuel in process and in reactor		66,773	7,466	—	74,239
Office equipment, furniture, and leasehold improvements		3,947	1,535	—	5,482
Generation assets under capital lease		456,945	127,953	—	584,898
Total accumulated depreciation		1,465,431	285,260	47,668	1,703,023
Net value of capital assets, being depreciated		6,217,987	(4,886)	2,236	6,210,865
Net value of all capital assets	$	6,459,718	266,329	294,151	6,431,896

In 2010, depreciation expense related to capital assets was approximately $150 million.

(7) Nine Mile Point Nuclear Power Station, Unit 2 (NMP2)

The Authority has an undivided 18% interest in Nine Mile Point 2 Nuclear Power Station (NMP2), located upstate, New York, operated by Constellation Energy Nuclear Group, LLC (Constellation) a division of Constellation Energy Group, Inc. (CEG).

The Authority's share of the rated capability of NMP2 is approximately 207 megawatts (MW). The rated capability of NMP2 and the Authority's share will increase to approximately 234 MW by April 2014 upon full completion of the extended power uprate (EPU) project. The net utility plant investment, excluding nuclear fuel, was approximately $420 million and $440 million as of December 31, 2011 and 2010, respectively. Generation from NMP2 and operating expenses incurred by NMP2 are shared by the Authority at its 18% ownership interest. The Authority is required to provide its share of financing for any capital additions to NMP2. Nuclear fuel costs associated with NMP2 are being amortized on the basis of the quantity of heat produced for the generation of electricity.

The Authority has an operating agreement for NMP2 with Constellation which provides for a management committee comprised of one representative from each co-tenant. Constellation controls the operating and maintenance decisions of NMP2 in its role as operator. The Authority and Constellation have joint approval rights for the annual business plan, the annual budget and material changes to the budget. In addition to its involvement through the management committee, the Authority maintains on-site nuclear oversight representation to provide additional support to protect the Authority's interests.

The Nuclear Regulatory Commission (NRC) granted a license extension for the Nine Mile Point 2 facility extending the license through October 2046.

(a) Nuclear Plant Decommissioning

Provisions for decommissioning costs for NMP2 are based on the most current site-specific study prepared by Constellation in 2010. The Authority's share of the total decommissioning costs for both the contaminated and non-contaminated portions (excluding the mark to market on the fund) is $69 million as of December 31, 2011 and is included in the balance sheet as a component of the asset retirement obligation. The value reflects the lengthening of the expected dormancy period prior to the commencement of decommissioning activities as a result of the license extension, partially offset by additional costs associated with the expected delay by the U.S. Department of Energy (DOE) in providing a permanent centralized repository for spent nuclear fuel and the reduction in the credit-adjusted risk-free interest rate. The Authority maintains a nuclear decommissioning trust fund (NDT) for its share of the decommissioning costs of NMP2, which as of December 31, 2011 and 2010 had an approximate value of $85 million and $81 million, respectively. Based on deposits and assumed investment returns related to these funds, the Authority believes that the value of these trusts will be sufficient to meet the Authority's expected decommissioning obligations.

(b) NMP2 Radioactive Waste

Constellation has contracted with the DOE for disposal of high-level radioactive waste (spent fuel) from NMP2. Despite a court order reaffirming the DOE's obligation to accept spent nuclear fuel by January 31, 1998, the DOE has not forecasted the start of operations of its high-level radioactive waste repository. The Authority has been advised by Constellation that the NMP2 spent fuel storage pool will no longer be able to accept a total fuel off-load beginning in May 2012. In order to regain this capability and to provide for future spent fuel storage, a dry fuel storage facility is being constructed for NMP2 spent fuel at the site, with completion anticipated in June 2012. The original storage facility license from the NRC will be for 20 years. The facility may subsequently be re-licensed in up to 40 year increments. The cost of the current facility, which is designed to service both Nine Mile Point 1 and NMP2, is expected to be $58 million, with LIPA's share being approximately $6 million. This facility will provide sufficient storage capacity with provisions for expansion, when needed, through the end of commercial operation in 2046. Spent fuel transfers from NMP2 spent fuel storage pool to the storage facility is scheduled for the third quarter of 2012. Spent fuel will remain in this storage facility at the site until such time as an ultimate repository is provided by DOE. The Authority reimburses Constellation for its 18% share of the disposal costs of spent fuel at a rate of $1.00 per megawatt hour of net generation, less a factor to account for transmission line losses. Such costs are included in the cost of fuel and purchased power.

(c) Nuclear Plant Insurance

Constellation procures public liability and property insurance for NMP2 and the Authority reimburses Constellation for its 18% share of those costs.

The Terrorism Risk Insurance Act (TRIA) of 2002 was extended by the Terrorism Risk Insurance Extension Act of 2005 and the Terrorism Risk Insurance Program Reauthorization Act of 2007. Under the TRIA, property and casualty insurance companies are required to offer insurance for losses resulting from certified acts of terrorism. Certified acts of terrorism are determined by the Secretary of the Treasury, in concurrence with the Secretary of State and Attorney General, and primarily are based upon the occurrence of significant acts of terrorism as part of an effort to coerce the civilian population of the United States or to influence the policy or affect the conduct of the United States Government by coercion. The nuclear property and accidental outage insurance programs, as discussed later in this section provide coverage for certified acts of terrorism.

Property losses resulting from noncertified acts of terrorism are covered as a common occurrence, meaning that if noncertified terrorist acts occur against one or more commercial nuclear power plants insured by the insurers of NMP2 within a 12-month period, such acts would be treated as one event and the owners of the currently licensed nuclear power plants in the United States would share one full limit of liability (currently $3.24 billion).

The Price Anderson Amendments Act mandates that nuclear power generators secure financial protection in the event of a nuclear accident. This protection must consist of two levels. The primary level provides liability insurance coverage of $375 million (the maximum amount available) in the event of a nuclear accident. If claims exceed that amount, a second level of protection is provided through a retrospective assessment of all licensed operating reactors. Currently, this "secondary financial protection" subjects each of the 104 presently licensed nuclear reactors in the United States to a retrospective assessment of up to $117.5 million for each nuclear incident, payable at a rate not to exceed $17.5 million per year. The Authority's interest in NMP2 could expose it to a maximum potential loss of $21.2 million per incident, through assessments of up to $3.2 million per year in the event of a serious nuclear accident at NMP2 or another licensed U.S. commercial nuclear reactor.

Constellation participates in the American Nuclear Insurers Master Worker Program that provides coverage for worker tort claims filed for radiation injuries. The policy provides a single industry aggregate limit of $200 million for occurrences of radiation injury claims against all those insured by this policy prior to January 1, 2003; $300 million for occurrences of radiation injury claims against all those insured by this policy between January 1, 2001 and January 1, 2010; and $375 million for occurrences of radiation injury claims against all those insured by this policy after January 1, 2010.

Constellation has also procured $500 million of primary nuclear property insurance and additional protection (including decontamination costs) of $1.25 billion of stand-alone excess property insurance and a $1.0 billion shared excess policy for Nine Mile Point through the Nuclear Electric Insurance Limited (NEIL). Each member of NEIL, including the Authority, is also subject to retrospective premium adjustments in the event losses at other member facilities. For its share of NMP2, the Authority could be assessed up to approximately $3.3 million per loss.

The Authority has obtained insurance coverage from NEIL for the expense incurred in purchasing replacement power during prolonged accidental outages. Under this program, coverage would commence twelve weeks after any accidental outage, with reimbursement from NEIL 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 over a three-year period.

(d) Other

In March 2012, the NRC issued additional safety enhancement requirement orders as a result of the disaster at the Fukushima Daiichi facility. These orders are applicable to operating US reactors, as well as all construction permits and combined license holders. The orders require safety enhancements to mitigate the response to natural events resulting in the loss of power at plants, reliable hardened containment vents and enhancing spent fuel pool instrumentation. Implementation of all safety enhancements is required to start promptly with completion within two refueling outages or by December 31, 2016, whichever comes first. The NRC has also requested each reactor reevaluate the seismic and flooding hazards at their site using present-day methods and information, conduct walk downs of their facilities to ensure protection against the hazards in their current design basis, and reevaluate their emergency communications systems and staffing levels. Constellation is preparing a response to these new regulations in accordance with NRC rules and indicates that they will comply with all NRC requirements within the allotted time-frame. The Authority believes that the costs of such safety enhancements, if any, will not have a material impact on the Authority's operations or cash flows.

(8) Cash, and Cash Equivalents and Investments

(a) Authority

The Authority's investments are managed by an external investment manager and consist of three accounts; the Operating Fund, the Rate Stabilization 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 and the Construction Fund is used to fund capital expenditures from the proceeds of the bonds. The Authority must maintain in the Rate Stabilization Fund an amount determined by the Authority from time to time in accordance with the Authority's bond resolution. In accordance with its agreements with the banks issuing letters of credit to secure the Authority's bonds, the Authority has agreed that such amount will not be less than $150 million. Additionally, the Authority is required to maintain compensating balances of $1.2 million.

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

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), commercial paper (A1 or P-1), corporate notes (AA- or Aa3), master notes (AA- or Aa3) and asset backed securities (AAA), certificates of deposit (AA- or Aa3), money-market mutual funds (AAAm or AAAm-G), investment contracts (AA- or Aa3), municipal obligations (AA- or Aa3), 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 and 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 10%; (iii) repurchase agreements up to 10% or $50 million; (iv) money-market mutual funds up to 75% maximum; and, (v) investment contracts up to 10%.

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 Aa3/AA- or higher, be fully collateralized above the Federal Deposit Insurance Corporation coverage. Commercial banks with long-term credit ratings of Aa3/AA- or higher do not require collateralization unless otherwise required by the Authority's Chief Financial Officer.

As of December 31, 2011 and 2010, the Authority had deposits of \$11 million and \$3 million, of which approximately \$9 million and \$2 million, respectively, were not collateralized or were uninsured. Uncollateralized balances were primarily the result of amounts temporarily held pending investment or disbursement and changes to FDIC limits. Collateral on the remaining deposits was held in an account for the Authority at 102% of the available deposit balance.

Interest Rate Risk: The Authority's investment policy states that investments have maturities of 12 months or less, generally. 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, 2011 and 2010, all of the Authority's investments had maturities of less than 12 months. The Authority's investment maturities are detailed in the chart below.

As of December 31, 2011, and 2010, the Authority had the following investments and maturities (amounts in thousands):

			2011 Investment maturities	
Deposit/investment type	**2011 Fair value**	**Percent of portfolio**	**Less than 3 months**	**3 months to 1 year**
Short-term discount notes:				
Commercial paper	$ 161,686	36%	151,687	9,999
Federal agencies	12,850	3%	12,850	—
Money-market mutual funds	261,790	58%	261,790	—
Cash and collateralized deposits	11,243	3%	11,243	—
Total	$ 447,569	100%	$ 437,570	9,999

Deposit/investment type		2010 Fair value	Percent of portfolio		2010 Investment maturities: Less than 3 months	2010 Investment maturities: 3 months to 1 year
Short-term discount notes:						
Commercial paper	$	267,038	56%	$	156,830	110,208
Federal agencies		6,499	1		1,000	5,499
Money-market mutual funds		202,003	42		202,003	—
Cash and collateralized deposits		3,486	1		3,486	—
Total	$	479,026	100%	$	363,319	115,707

(b) LIPA

LIPA maintains a separate investment policy applicable to the long-term investments in the Nuclear Decommissioning Trusts (NDT) which is held to meet LIPA's obligation with respect to the eventual decommission of LIPA's 18% interest in the Nine Mile Point 2 nuclear facility. LIPA guidelines detail permissible investments and portfolio restrictions. LIPA reviews its investment policy at least annually 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 its decommissioning obligations.

(c) Credit Risk

LIPA's 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 A or better rating; mortgage obligations rated AA or higher; commercial paper with a rating of A1 or P1; certificates of deposit; Eurodollar certificates of deposit and bankers acceptances of domestic banks with A+ rating or better, short-term money market investment accounts that conform to the aforementioned permissible investments; and with respect to the LIPA's long-term NDT investment portfolio only, equity investments limited to portfolio funds of securities designed to replicate the overall market measured by the S&P 500 Index, and futures contracts on the S&P 500 Index. Within the NDT investment portfolio, the use of equity investments as a permissible investment 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 AA or better with no more than 30% of the portfolio invested in notes and bonds rated A and no more than 20% of the portfolio invested in municipal securities.

Concentration of Credit Risk: To address this risk, LIPA's 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: LIPA does not have a policy relative to custodial credit risk of its deposits, however, as a practical matter, LIPA defers to the policies of the Authority, as discussed above.

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. government/Credit Bond 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, 2011, and 2010, LIPA had the following investments (amounts in thousands):

Investment type		2011 Fair value	Percent of portfolio
Corporate notes and bonds	$	18,555	22%
Mortgage obligations		692	1%
U.S. government and its agencies obligations		35,141	41%
Money-market mutual funds		138	0%
Commingled equity fund		30,877	36%
Total	$	85,403	100%

Investment type		2010 Fair value	Percent of portfolio
Corporate notes and bonds	$	17,297	21%
Mortgage obligations		2,608	3%
U.S. government and its agencies obligations		29,791	37%
Money-market mutual funds		502	1%
Commingled equity fund		30,374	38%
Total	$	80,572	100%

The overall duration of the three individual accounts averaged 5.9 and 5.6 years at December 31, 2011 and 2010, respectively, and is within the limits described by LIPA's investment guidelines.

(9) Long-Term and Short-Term Debt

The Authority financed the cost of acquiring the T&D system and the refinancing of certain of LILCO's outstanding debt by issuing approximately $6.73 billion aggregate principal amount of Electric System General Revenue Bonds and Electric System Subordinated Revenue Bonds (collectively, the Bonds). In conjunction with the issuance of the Bonds, 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 transmission and distribution system, including the right to collect and receive the same. In exchange for the transfer of these rights to the Authority, LIPA received the proceeds of the Bonds evidenced by a Promissory Note.

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 LIPA's transmission and distribution system and has been pledged by LIPA to the Authority.

The Authority's bond and note indebtedness and other long-term liabilities as of December 31, 2011 are comprised of the following obligations (amounts in thousands):

	Beginning balance	Accretion/ additions		Maturities	Refundings	Ending balance	Due within one year
Authority debt:							
Electric system general revenue bonds:							
Series 1998A	$ 217,630	7,225	(a)	81,800	—	143,055	12,970
Series 1998B	3,745	—		3,745	—	—	—
Series 2000A	401,774	22,448	(a)	31,260	—	392,962	31,705
Series 2001A	165,175	—		—	—	165,175	—
Series 2003B	250,265	—		12,800	—	237,465	87,710
Series 2003C	256,000	—		—	—	256,000	—
Series 2003 D	73,625	—		—	—	73,625	—
Series 2003 H-J	167,600	—		—	—	167,600	—
Series 2003 L-O	134,000	—		—	—	134,000	—
Series 2004A	200,000	—		—	—	200,000	—
Series 2006A	839,245	—		—	—	839,245	—
Series 2006B	96,955	—		—	—	96,955	—
Series 2006C	198,020	—		—	—	198,020	—
Series 2006D	326,260	—		690	—	325,570	47,680
Series 2006E	507,600	—		—	—	507,600	—
Series 2006F	514,495	—		81,325	—	433,170	97,960
Series 2008A	605,055	—		—	—	605,055	—
Series 2008B	149,340	—		—	—	149,340	—
Series 2009A	435,825	—		—	—	435,825	—
Series 2010A	193,325	—		—	—	193,325	—
Series 2010B	210,000	—		—	—	210,000	—
Series 2011A	—	250,000		—	—	250,000	—
Subtotal	5,945,934	279,673		211,620	—	6,013,987	278,025
Electric system subordinate revenue bonds:							
Series 1-3	525,000	—		—	—	525,000	—
Series 8	26,480	—		26,480	—	—	—
Subtotal	551,480	—		26,480	—	525,000	—
LIPA debt:							
NYSERDA notes	155,420	—		—	—	155,420	—
Net unamortized discounts/premiums and deferred amortization	(51,490)	11,693		(3,024)	—	(36,773)	—
Total bonds and notes, net of unamortized discounts/premiums	$ 6,601,344	291,366		235,076	—	6,657,634	278,025
Other long-term liabilities:							
Deferred credits	$ 133,024	12,161		66,406	—	78,779	—
Borrowings	110,297	—		4,982	—	105,315	—
Claims and damages	21,648	1,302		1,677	—	21,273	—
Capital lease obligations	2,970,126	196,563		135,712	—	3,030,977	147,656
Total other long-term liabilities	$ 3,235,095	210,026		208,777	—	3,236,344	147,656

(a) Represents accretion of capital appreciation bonds

The Authority's bond and note indebtedness and other long-term liabilities as of December 31, 2010 are comprised of the following obligations (amounts in thousands):

	Beginning balance	Accretion/ additions		Maturities	Refundings	Ending balance	Due within one year
Authority debt:							
Electric system general revenue bonds:							
Series 1998A	$ 288,389	6,861	(a)	77,620	—	217,630	81,800
Series 1998B	82,125	—		78,380	—	3,745	3,745
Series 2000A	409,780	22,819	(a)	30,825	—	401,774	31,260
Series 2001A	165,175	—		—	—	165,175	—
Series 2003B	262,510	—		12,245	—	250,265	12,800
Series 2003C	256,000	—		—	—	256,000	—
Series 2003 D	73,625	—		—	—	73,625	—
Series 2003 E-G	165,000	—		—	165,000	—	—
Series 2003 H-J	167,600	—		—	—	167,600	—
Series 2003 K	47,000	—		—	47,000	—	—
Series 2003 L-O	134,000	—		—	—	134,000	—
Series 2004A	200,000	—		—	—	200,000	—
Series 2006A	839,245	—		—	—	839,245	—
Series 2006B	96,955	—		—	—	96,955	—
Series 2006C	198,020	—		—	—	198,020	—
Series 2006D	326,925	—		665	—	326,260	690
Series 2006E	507,600	—		—	—	507,600	—
Series 2006F	514,495	—		—	—	514,495	81,325
Series 2008A	605,055	—		—	—	605,055	—
Series 2008B	149,340	—		—	—	149,340	—
Series 2009A	435,825	—		—	—	435,825	—
Series 2010A	—	193,325		—	—	193,325	—
Series 2010B	—	210,000		—	—	210,000	—
Subtotal	5,924,664	433,005		199,735	212,000	5,945,934	211,620
Electric system subordinate revenue bonds:							
Series 1-3	$ 525,000	—		—	—	525,000	—
Series 8	51,705	—		25,225	—	26,480	26,480
Subtotal	576,705	—		25,225	—	551,480	26,480
LIPA debt:							
NYSERDA notes	155,420	—		—	—	155,420	—
Net unamortized discounts/premiums and deferred amortization	(36,880)	(15,594)		—	(984)	(51,490)	—
Total bonds and notes, net of unamortized discounts/premiums	$ 6,619,909	417,411		224,960	211,016	6,601,344	238,100
Other long-term liabilities:							
Deferred credits	$ 203,637	8,700		79,313	—	133,024	—
Borrowings	114,520	—		4,223	—	110,297	—
Claims and damages	20,207	2,268		827	—	21,648	—
Capital lease obligations	3,098,079	—		127,953	—	2,970,126	135,710
Total other long-term liabilities	$ 3,436,443	10,968		212,316	—	3,235,095	135,710

(a) Represents accretion of capital appreciation bonds

The Authority's schedule of capitalization for the years ended December 31, 2011 and 2010 is as follows (amounts in thousands):

Electric system	Maturity	Interest rate		Series	December 31, 2011	December 31, 2010
Electric system general revenue bonds:						
Serial bonds	December 1, 2011	5.500%	a	1998 A	$ —	81,800
Capital appreciation bonds	December 1, 2012 to 2028	5.100% to 5.300%	a	1998 A	143,055	135,830
Serial bonds	April 1, 2011	4.500%	a	1998 B	—	3,745
Capital appreciation bonds	June 1, 2012 to 2029	5.480% to 5.950%	a	2000 A	392,962	401,774
Serial bonds	September 1, 2013 to 2014	4.600% to 4.700%	a,	2001 A	745	745
Term bonds	September 1, 2027 to 2029	5.000% to 5.125%	a, c	2001 A	164,430	164,430
Serial bonds	June 1, 2012 to 2014	5.250%	a	2003 B	237,465	250,265
Serial bonds	September 1, 2013 to 2028	4.25% to 5.00%	a, c	2003 C	70,480	70,480
Term bonds	September 1, 2027 to 2033	5.00% to 5.25%	a, c	2003 C	185,520	185,520
Term bonds	December 1, 2029	0.75% to 1.30%	b, c	2003 D-O	375,225	375,225
Serial bonds	September 1, 2013 to 2025	3.80% to 4.875%	a, c	2004 A	33,900	33,900
Term bonds	September 1, 2029 to 2034	5.00% to 5.10%	a	2004 A	166,100	166,100
Serial bonds	December 1, 2016 to 2026	4.00% to 5.25%	a, c	2006A	839,245	839,245
Serial bonds	December 1, 2035	4.500%	a, c	2006B	4,240	4,240
Term bonds	December 1, 2035	5.000%	a	2006B	92,715	92,715
Term bonds	September 1, 2035	5.000%	a	2006C	198,020	198,020
Serial bonds	September 1, 2012 to 2025	4.00% to 5.00%	a, c	2006D	325,570	326,260
Serial bonds	December 1, 2017 to 2022	4.00% to 5.00%	a, c	2006E	507,600	507,600
Serial bonds	May 1, 2012 to 2028	4.00% to 5.00%	a, c	2006F	320,590	401,915
Term bonds	May 1, 2033	4.250%	a	2006F	112,580	112,580
Term bonds	May 1, 2033	5.50% to 6.00%	a	2008A	605,055	605,055
Term bonds	April 1, 2019 to 2033	5.25% to 5.75%	a	2008B	149,340	149,340
Term bonds	April 1, 2014 to 2039	3.00% to 6.25%	a	2009A	435,825	435,825
Serial bonds	May 1, 2014 to 2015	2.50% to 5.00%	a	2010A	193,325	193,325
Term bonds	May 1, 2020 to 2041	4.85% to 5.85%	a,d	2010B	210,000	210,000
Serial bonds	May 1, 2016 to 2036	4.00% to 5.00%	a	2011A	113,360	—
Term bonds	May 1, 2038	5.000%	a	2011A	136,640	—
Electric system subordinated:						
Revenue bonds	May 1, 2033	0.25% to 0.30%	b, c	Series 1A-3A	275,000	275,000
	May 1, 2033	0.05% to 0.15%	b, c	Series 1B-3B	250,000	250,000
	April 1, 2011	4.00% to 5.00%	a	Series 8	—	26,480
Total general and subordinated revenue bonds					6,538,987	6,497,414
Commercial paper notes		0.110%	b	CP-1	150,000	100,000
		0.110%	b	CP-3	50,000	100,000
					200,000	200,000
NYSERDA Financing notes:						
Pollution control revenue bonds	March 1, 2016	5.150%	a	1985 A,B	108,020	108,020
Electric facilities revenue bonds	November 1, 2023	5.300%	a	1993 B	29,600	29,600
	October 1, 2024	5.300%	a	1994 A	2,600	2,600
	August 1, 2025	5.300%	a	1995 A	15,200	15,200
Total NYSERDA financing notes					155,420	155,420
Unamortized premium/discount and deferred amortization					(36,773)	(51,490)
Total long-term debt					6,857,634	6,801,344
Less current maturities and short-term debt					478,025	438,100
Long-term debt					6,379,609	6,363,244
Net assets					395,970	377,169
Total capitalization					$ 6,775,579	6,740,413

a Fixed rate.
b Variable rate (rate presented is as of December 31, 2011).
c Certain bonds of this series are subject to interest rate exchange agreements – see note 4.
d Taxable Build America Bonds subject to 35% federal subsidy, rate shown is pre-subsidy level.

The debt service requirements for the Authority's bonds (excluding commercial paper notes) as of December 31, 2011, are as follows (amounts in thousands):

Due		Principal	Interest	Net swap payments	Total
2012	$	278,025	284,056	24,190	586,271
2013		176,060	281,444	16,167	473,671
2014		280,720	278,242	11,632	570,594
2015		289,585	271,493	7,446	568,524
2016		311,840	260,338	7,097	579,275
2017 – 2021		1,180,745	1,159,454	35,154	2,375,353
2022 – 2026		1,436,450	899,605	33,485	2,369,540
2027 – 2031		1,500,255	612,333	13,388	2,125,976
2032 – 2036		1,194,880	217,917	—	1,412,797
2037 – 2041		373,335	54,087	—	427,422
		7,021,895	4,318,969	148,559	11,489,423
Unamortized discounts/premiums		(36,773)	—	—	(36,773)
Unaccreted interest on capital appreciation bonds		(327,488)	—	—	(327,488)
Total	$	6,657,634	4,318,969	148,559	11,125,162

Future debt service on the variable rate bonds and floating rate portion of any floating-to-fixed rate swaps use an assumed rate of 2.00% for 2012; 3.00% for 2013; 3.50% for 2014, and 4.00% thereafter. 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.

(a) Electric System General Revenue Bonds

2011

In September 2011, the Authority issued $250 million of its Electric System General Revenue Bonds, Series 2011A. The proceeds of these fixed rate bonds, including the original issue premium of $12 million, were used to fund LIPA's capital programs and to pay bond issuance costs. The 2011A bonds have an average life of 21.9 years and an all-in cost of 4.70%.

2010

In May 2010, the Authority issued $193 million of its Electric System General Revenue Bonds, Series 2010A. The proceeds of these fixed rate bonds, including the original issue premium of $20 million, were used to redeem $212 million of outstanding insured variable rate securities in a current refunding and to pay bond issuance costs. The refunding produced an approximate $28 million net present value savings. The 2010A bonds have an average life of 4.5 years and an all-in cost of 2.50%.

Also, in May 2010, the Authority issued $210 million of its Electric System General Revenue Bonds, Series 2010B. The 2010B bonds are taxable Build America Bonds and the Authority receives an interest subsidy from the federal government equal to 35% of the interest paid. The proceeds of these fixed rate bonds outstanding are used to finance the on-going capital program. The 2010B bonds have an average life of 22 years and an all-in cost of 3.75%.

(b) Interest Rate Swap Agreements

The Authority has entered into several interest rate swap agreements with various counterparties to modify the effective interest rate on outstanding debt. For a further discussion, see note 4.

(c) Commercial Paper Notes

The Supplemental Bond Resolution authorizes the issuance of Commercial Paper Notes, Series CP-l through CP-3 (Notes) up to a maximum amount of $300 million. The aggregate principal amount of the Notes outstanding at any time may not exceed $300 million. The Notes do not have maturity dates of longer than 270 days from their date of issuance and as Notes mature, the Authority continually replaces them with additional Notes. In connection with the issuance of the Notes, the Authority entered into a Letter of Credit and Reimbursement Agreement, which was renegotiated in 2006. Under the terms of that renegotiated Letter of Credit and Reimbursement Agreement, $250 million was scheduled to expire June 15, 2011 and the remaining $50 million was scheduled to expire on December 15, 2015, subject to the right of early termination by the bank on June 15, 2012. In 2011, the Authority negotiated an extension of the June 15, 2011 expiration date to January 31, 2012 in conjunction with the issuance of a request for proposals for letter of credit capacity support for the Notes. In January 2012, the Authority entered into three new Letter of Credit and Reimbursement Agreements totaling $300 million in principal amount. These Letter of Credit and Reimbursement Agreements are for a period of three years with a stated expiration date of January 27, 2015.

The Authority's short-term indebtedness as of December 31, 2011 and 2010 is comprised of the following obligations (amounts in thousands):

		2011			
		Beginning balance	**Issuances**	**Retirements**	**Ending balance**
Short-term debt – CP-1	$	100,000	750,000	(700,000)	150,000
Short-term debt – CP-3		100,000	625,558	(675,558)	50,000
	$	200,000	1,375,558	(1,375,558)	200,000

		2010			
		Beginning balance	**Issuances**	**Retirements**	**Ending balance**
Short-term debt – CP-1	$	100,000	210,200	(210,200)	100,000
Short-term debt – CP-3		100,000	608,100	(608,100)	100,000
	$	200,000	818,300	(818,300)	200,000

(d) *Fair Values of Long-Term Debt*

The fair values of the Authority's long-term debt as of December 31, 2011 and 2010 were as follows (amounts in thousands):

		December 31, 2011	December 31, 2010
Electric System General Revenue Bonds, Series 1998 A	$	172,259	233,769
Electric System General Revenue Bonds, Series 1998 B		—	3,781
Electric System General Revenue Bonds, Series 2000 A		493,420	455,237
Electric System General Revenue Bonds, Series 2001 A		165,353	165,236
Electric System General Revenue Bonds, Series 2003 B		253,030	271,566
Electric System General Revenue Bonds, Series 2003 C		267,462	253,990
Electric System General Revenue Bonds, Series 2003 D		73,625	73,625
Electric System General Revenue Bonds, Series 2003 H-J		167,600	167,600
Electric System General Revenue Bonds, Series 2003 L-O		134,000	134,000
Electric System General Revenue Bonds, Series 2004 A		205,682	195,432
Electric System General Revenue Bonds, Series 2006 A		908,309	862,530
Electric System General Revenue Bonds, Series 2006 B		99,649	91,131
Electric System General Revenue Bonds, Series 2006 C		204,022	186,856
Electric System General Revenue Bonds, Series 2006 D		345,656	336,821
Electric System General Revenue Bonds, Series 2006 E		568,029	536,783
Electric System General Revenue Bonds, Series 2006 F		458,587	517,784
Electric System General Revenue Bonds, Series 2008 A		667,637	626,876
Electric System General Revenue Bonds, Series 2008 B		171,609	159,235
Electric System General Revenue Bonds, Series 2009 A		493,300	459,240
Electric System General Revenue Bonds, Series 2010A		212,530	212,238
Electric System General Revenue Bonds, Series 2010B		225,712	185,891
Electric System General Revenue Bonds, Series 2011A		269,870	—
Electric System Subordinated Revenue Bonds, Series 1-3 and 1-6		525,000	525,000
Electric System Subordinated Revenue Bonds, Series 8F		—	26,735
NYSERDA Notes		155,823	156,430
Total	$	7,238,164	6,837,786

(10) Retirement Plans

The Authority participates in the New York State Employees' Retirement System (the System), which is a cost-sharing, multi-employer, and public employee retirement system. The plan benefits are provided under the provisions of the New York State Retirement and Social Security Law that are guaranteed by the State Constitution and may be amended only by the State Legislature. For full time employees, membership in and annual contributions to the System are required by the New York State Retirement and Social Security Law. The System offers plans and benefits related to years of service and final average salary, and, effective January 1, 2010 benefits for new members vest after ten years of accredited service, all others generally vested after five years.

Members of the System with less than 10 years of service or 10 years of membership contribute 3% of their gross salaries and the Authority pays the balance of the annual contributions for these employees. After 10 years of service or membership, members of the System no longer contribute 3% of their gross salaries and the Authority pays the entire amount of the annual contributions of these employees. Effective January 1, 2010, all new members contribute 3% of their gross salaries for their entire career.

Under this plan, the Authority's required contributions and payments made to the System were approximately $1.6 million, $1.1 million, and $572,000, for the years ended December 31, 2011, 2010, and 2009, respectively. Contributions are made in accordance with funding requirements determined by the actuary of the System using the aggregate cost method.

The State of New York and the various local governmental units and agencies which participate in the Retirement System are jointly represented, and benefits for Authority employees are not separately computed. The New York State Employees' Retirement System issues a publicly available financial report. The report may be obtained from the New York State and Local Retirement Systems, 110 State Street, Albany, New York 12244.

(11) Postemployment Healthcare Plan

(a) Plan Description

The Authority is a participating employer in the New York State Health Insurance Program (NYSHIP) which is administered by the State of New York as an agent multiple employer defined benefit plan. Under the plan, 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 become eligible for these benefits at 55 years of age when the employee has five years of State service. In calculating the five year service requirement, all of the employee's service need not be with the Authority, but may be a composite of New York State service elsewhere, with a minimum of one year with the Authority. Employees with no prior State service must work a minimum of five years before they and their dependents are eligible for the retirement medical benefits. Eligible retirees contribute 10% of the cost of single coverage and 25% of the cost of dependent coverage for health insurance benefits. Participants include approximately 96 employees and retired and/or spouses of retired employees who were eligible to receive these benefits at December 31, 2011. NYSHIP does not issue a stand-alone financial report and NYSHIP's agent activities are included within the financial statements of the State of New York.

The Authority accounts for its OPEB obligations, in accordance with GASB Statement No. 45, *Accounting and Financial Reporting for Post-Employment Benefits Other Than Pensions. Actuarial* (GASB No. 45) 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. Since the Authority expensed the entire prior service cost in 2007, 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 (which was $20 million at December 31, 2011), and as the Authority has not funded the "required" amount, future valuations may produce larger ARCs. The current period ARC is approximately $2.4 million as detailed in (d).

(b) Funding

The contribution requirements (funding) of the Authority's Net OPEB obligation are at the discretion of management and the Board of Trustees. The Net OPEB obligation is paid on a pay-as-you-go basis. The Authority has not funded a qualified trust or its equivalent.

(c) Actuarial Methods and Assumption

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 2011 and 2010 actuarial valuation, the projected unit credit actuarial cost method was used. The actuarial assumptions included a 3.75% investment rate of return (net of administrative expenses) and an annual healthcare cost trend rate of 10% (net of administrative expenses) including inflation, declining 1% each year to an ultimate trend rate of 5%. Both rates include a 3% inflation assumption.

(d) OPEB Status and Funding Progress

The OPEB obligation, which is included in deferred credits, and the funded status of the plan as of December 31, 2011 and 2010 is as follows (amounts in thousands):

		2011	2010
Annual OPEB cost:			
Annual required contribution (ARC):			
Normal cost	$	1,557	1,482
Amortization payment		17,694	15,718
Interest to the end of the year		718	642
Total		19,969	17,842
ARC adjustment		(18,249)	(16,190)
Interest on net OPEB obligation		667	590
Annual OPEB cost	$	2,387	2,242
Net OPEB obligation:			
Net OPEB obligation at beginning of fiscal year	$	17,825	15,714
Annual required contribution:			
Annual OPEB cost		2,387	2,242
Employer contribution:			
Payments for retirees during the year to a trust		(235)	(131)
Net OPEB obligation at end of fiscal year	$	19,977	17,825

Actuarial valuation date		2011	2010
Actuarial value of assets	$	—	—
Accrued actuarial liability (AAL)		18,688	16,680
Unfunded AAL		18,688	16,680
Funded ratio		—%	—%
Covered payroll	$	11,401	10,576
UAAL as % covered payroll		163.9%	157.7%

(12) Commitments and Contingencies

(a) Power Supply Agreement (PSA)

The PSA provides for the sales to the Authority by KeySpan of all of the capacity, energy and, ancillary service output from the oil and gas-fired generating plants on Long Island formerly owned by LILCO. Such sales of capacity and energy 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 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) reasonably incurred expenses that are outside of the control of KeySpan. The PSA rates were reset in 2009, in accordance with the PSA agreement and as approved by FERC, and will continue through May 2013 at which time the Authority has the option to extend the PSA at substantially similar terms for a period of 15 years, or to negotiate new mutually agreeable terms. The rates are adjusted annually in accordance with the formula established in the PSA. The annual capacity charge in 2011 and 2010 was approximately $437 million and $431 million, respectively. The variable charge remains constant through May 2013 at $0.90/Mwh of electric power generated by the plants.

The PSA provides incentives and penalties for up to $4 million annually to maintain the output capability of the facilities, as measured by annual industry-standard tests of operating capability, and to maintain/or make capital improvements which benefit plant availability. The performance incentives were approximately $3.7 million and $2.5 million in 2011 and 2010, respectively.

(b) Purchased Power and Transmission Agreements Assumed from LILCO

As a result of the merger with LILCO, the Authority became party to power purchase agreements (PPAs) with Independent Power Producers (IPPs) and the New York Power Authority (NYPA) for electric generating capacity. Certain of these agreements have been renegotiated by the Authority or modified to comply with market rules instituted by the New York Independent System Operator (NYISO).

Under the terms of a 1989 agreement with NYPA, which will expire in 2015, the Authority purchases power from a pumped storage plant in upstate New York at tariff rates established by NYPA. Under the terms of a 1994 agreement with NYPA which will expire in April 2020, the Authority purchases the electric capacity and energy produced at the NYPA facility located within the service territory at Holtsville, New York.

The Authority also became party to contracts with NYPA and Con Edison for firm transmission (wheeling) capacity in connection with the pumped storage PPA, as well as a contract with NYPA associated with a transmission cable that was constructed, in part, for the benefit of the Authority. With the inception of the NYISO on November 18, 1999, these transmission contracts were provided with “grandfathered rights” status. The Authority was provided with the opportunity to convert its grandfathered rights for Existing Transmission Agreements (ETAs) into Transmission Congestion Contracts (TCCs). Although the Authority has converted its ETA’s into TCCs, the Authority will continue to pay all transmission charges per the ETAs. In return, the Authority receives revenues from congestion charges collected by the NYISO. All such charges and revenue are considered components of or reductions to fuel and purchased power costs.

With respect to PPAs entered into with the IPPs, the Authority is obligated to purchase all the energy they make available to the Authority. However, LIPA has no obligation to the IPPs if they fail to deliver energy.

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

The following table represents the Authority's commitments under the PPAs and transmission contracts assumed from LILCO, as renegotiated or modified (amounts in thousands):

		PPA	Firm transmission	IPPs*	Total
Years ended:					
2012	$	41,784	21,940	68,300	132,024
2013		40,117	23,330	53,700	117,147
2014		39,939	23,430	53,100	116,469
2015		40,168	23,080	57,100	120,348
2016		40,558	22,640	59,700	122,898
2017 through 2021		145,684	94,750	—	240,434
2022 through 2026		—	22,669	—	22,669
2027 through 2031		—	24,955	—	24,955
2032 through 2035		—	28,944	—	28,944
Subtotal		348,250	285,738	291,900	925,888
Less imputed interest		70,700	89,958	38,400	199,058
Total	$	277,550	195,780	253,500	726,830

* Assumes full performance by NYPA and the IPPs.

(c) Additional 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 as needed), for the term of each contract, which vary in duration up to 30 years from contract initiation date.

The Authority has also entered into several agreements to purchase renewable energy from on and off-Island sources. In 2010, the Authority entered into two additional contracts for up to 50 MW of power to be produced by solar photovoltaic facilities constructed at various sites on Long Island. Two sites began operation in late 2011 and additional sites are expected to be completed in 2012 (the additional sites are included in the table below and are assumed to be operating leases until all sites are completed.)

In accordance with the provisions of FASB ASC 840 *Leases* certain of these power producing facilities have been accounted for as capitalized lease obligations. Other facilities which do not meet the criteria for capitalization under FASB ASC 840 *Leases* are being accounted for as operating leases.

The following table represents the minimum payments under these various capacity and/or energy contracts (amounts in thousands):

Minimum lease/rental payments:		Capital leases	Operating leases
2012	$	305,700	143,604
2013		307,104	146,170
2014		309,011	148,706
2015		310,882	151,386
2016		312,944	153,308
2017 through 2021		1,330,475	656,870
2022 through 2026		1,158,143	286,204
2027 through 2031		429,829	163,532
2032 through 2034		13,493	4,626
Total		4,477,581	1,854,406
Less imputed interest		1,446,604	542,932
Net present value	$	3,030,977	1,311,474

(d) Office Lease

The Authority's office lease agreement terminated on April 30, 2011 and a new lease commenced on May 1, 2011.

The Authority's new 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 Authority recorded a deferred credit to reflect the excess of rent expense over cash payments since inception of the lease.

The termination date of the new lease agreement is April 30, 2024. The future minimum payments under the lease are as follows for the years ended (amounts in thousands):

Minimum lease/rental payments:		
2012	$	244
2013		740
2014		1,150
2015		1,577
2016		1,629
2017 through 2021		8,973
2022 through 2024		4,697
Total		19,010
Less imputed interest		4,664
Net present value	$	14,346

(e) 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. Liability related to construction projects and similar risks is transferred through contractual indemnification and compliance with Authority insurance requirements. The Authority also has various insurance coverages on its interest in Nine Mile Point Nuclear Power Station, Unit 2 as disclosed in detail in note 7.

The Authority is self- insured up to $3 million for general liability, including automobile liability. The Authority's is self-insured for damage to its poles and wires and the equipment attached thereto. The Authority's transmission assets, such as substations, are self-insured up to $7.5 million and distribution assets are self- insured up to $1.5 million, except for transformers which are self-insured up to $2.0 million. The Authority purchased commercially available excess general liability and property insurance for claims above the self-insurance provision specified above.

(f) Other

Following the issuance of a competitive solicitation for utility management services of LIPA's transmission and distribution system (T&D System), in December 2011, the LIPA Trustees approved the selection of PSEG to succeed National Grid Electric Services, LLC (NGES) as the Service Provider to operate, maintain, and make capital improvements to the T&D System when LIPA's current Management Service Agreement (MSA) with National Grid expires on December 31, 2013. The new agreements with PSEG are awaiting receipt of required regulatory approvals.

As a result the impending expiration of the MSA, LIPA has been reviewing its rights and responsibilities under its various contracts related to both transitioning to a new management contract and new service provider. In this regard, the agreements between LIPA and National Grid provide, among other things, that upon termination of the MSA, if a third party succeeds NGES as the service provider, then the successor shall assume the rights and obligations of NGES regarding certain employee benefit plan liabilities and that NGES and LIPA shall enter into agreements to separate the new service provider obligations from those which NGES shall retain. The agreement further states that if the successor service provider fails to discharge these obligations, then NGES may pursue its rights first against the new service provider and secondarily against LIPA. The new agreement with PSEG would not require PSEG to pay employee benefit plan costs; rather, LIPA would fund the costs for employees providing service to LIPA.

LIPA is reviewing the agreement to determine which, if any, employee plan obligations need to be separated at the end of the MSA. Although LIPA has consistently funded the annual plan costs throughout the MSA term, NGES has advised LIPA that there are pension and other employee plan benefit obligations that are currently substantially underfunded or unfunded (such as OPEBs). The nature and extent of LIPA's potential obligation for such unfunded costs, if any, cannot be reasonably predicted at this time.

(13) Legal Proceedings

(a) Authority to Set Rates

Under current State law, the Board of Trustees of the Authority is empowered to set rates for electric service in the Service Area without being required by law to obtain the approval of the PSC or any other State regulatory body. However, in connection with the approval of the LIPA/LILCO Merger by the PACB in 1997, the Authority agreed that it would comply with the condition imposed by the PACB and not impose any permanent increase, nor extend or reestablish any portion of a temporary rate increase, in average customer rates over a 12-month period in excess of 2.5% without approval of the PSC, following a full evidentiary hearing.

Legislation was unanimously passed by the New York State Legislature in June 2008, seeking to amend the LIPA Act and the State Public Service Law to require the approval by the PSC of an increase in LIPA's average customer rates exceeding 2.5% over a 12-month period or to extend or reestablish any portion of a temporary rate increase exceeding 2.5%. Were such legislation to have become law, the Authority would have had to notify the PSC of any proposed rate increase, extension or re-establishment exceeding 2.5% of average rates over a 12-month period. Approval of any such request by the PSC would have required a full evidentiary hearing by the PSC. The proposed legislation was vetoed on September 4, 2008 by Governor Paterson and therefore has not been enacted into law. A revised version of the 2008 bill was introduced in both the Assembly and Senate in 2009. The Assembly passed the bill on June 16, 2009, however, the Senate did not take any further action in 2009 and the legislative session ended without the bill being passed. A further revised bill was introduced in both the Assembly and Senate in 2010 and on March 10, 2010, the Assembly passed the bill. Again in 2011, the rate regulation bill was introduced and on April 4, 2011, it passed in the Senate and on June 16, 2011, it passed in the Assembly. Subsequently, a new bill requiring LIPA to undergo an audit of its management and operations was introduced and passed in both houses, and signed into law by Governor Cuomo. At the time the Governor signed the audit bill into law, the rate regulation bill was repealed. It is not expected that a rate regulation bill will be proposed during this session based on remarks made by the bill sponsors; however, the Authority cannot predict with certainty that other similar legislation will not be introduced and acted upon in the future.

(b) Environmental

In connection with the LIPA/LILCO Merger (the Merger), KeySpan and the Authority entered into Liabilities Undertaking and Indemnification Agreements which, when taken together, provide, generally, that environmental liabilities will be divided between KeySpan and the Authority on the basis of whether they relate to assets transferred to KeySpan or retained by the Authority as part of the Merger. In addition, to clarify and supplement these agreements, KeySpan 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 KeySpan after the Merger (the Transferred Business).

National Grid, who subsequently purchased KeySpan in 2007, is now responsible for all liabilities arising from all manufactured gas plant operations on Long Island (MGP Sites), including those currently or formerly operated by National Grid or any of its predecessors, whether or not such MGP Sites related to the Transferred Business or the Retained Business. In addition, National Grid 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 National Grid as part of the capacity charge under the 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 53.6% to LIPA and 46.4% to National Grid, as provided for in the Merger.

(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 the Superfund Legislation), parties who generated or arranged for disposal of hazardous substances are liable for costs incurred by the Environmental Protection Agency (EPA) or others who are responding to a release or threat of release of the hazardous substances.

Port Washington Landfill – LILCO is a PRP at this 54-acre municipal solid waste landfill located in the Town of North Hempstead. The landfill operated from 1973 to 1983. Since January 2001, LILCO and 11 other parties have been signing tolling agreements with the New York State Attorney General to extend the statute of limitations under CERCLA. The current tolling agreement expires on June 15, 2012. 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. The 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. The JDG is in negotiations with the Attorney General to resolve this matter. The Authority does not believe that its share of any settlement agreement will have a material adverse effect on its financial position, cash flows or results of operations.

(d) Environmental Matters which may be Recoverable from the Authority by KeySpan Through the PSA

Asharoken – In March 1996, the Village of Asharoken (the Village) filed a lawsuit against LILCO in the New York Supreme Court, Suffolk County (Incorporated Village of Asharoken, New York, et al. v. Long Island Lighting Company). Although the Village's negligence claims were dismissed, the nuisance causes of action remained at issue. Specifically, the Village sought injunctive relief based upon allegations that the design and construction of the Northport Power Plant upset the littoral drift of sand in the area, thereby causing beach erosion. In a related matter, certain individual residents of the Village commenced an action in New York Supreme Court, Suffolk County seeking similar relief (Sbarro v. Long Island Lighting Company). The cases were tried jointly before a judge without a jury. The trial was completed in December 2002 and the parties filed post-trial briefs in March 2003. The judge dismissed the case after reviewing the existing and supplemental record. The Village subsequently filed a notice of appeal of this decision and, on December 22, 2008, the Appellate Division unanimously affirmed the judge's dismissal of the Village of Asharoken's lawsuit against LILCO.

Despite the decision of the Appellate Division, the U.S. Army Corps of Engineers, as a condition of an existing permit, required National Grid to deposit 45,000 cubic yards of sand every three years, starting in 2010, on beaches within the Village. The Authority and National Grid complied with this requirement in 2010 and intend to comply in 2013 and thereafter subject to future negotiations and potential relief. The Authority does not believe that this will have a material adverse effect on its financial position, cash flows or results of operations.

(e) Asbestos Proceedings

Litigation is pending in State Court against the Authority, LILCO, KeySpan 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.

(f) Future Environmental Compliance Obligations

The Authority, through its contractual obligations to KeySpan under the PSA and the MSA, and other Independent Power Producers and transmission cable operators, under various power purchase agreements (PPAs), may be subject to the cost of compliance with various current and potential future environmental regulations as promulgated by the federal government and by state and local governments with respect to environmental matters, such as emission of air pollutants, greenhouse gases, cooling water for generation, electromagnetic fields, the handling and disposal of toxic substances and hazardous and solid wastes, the handling and use of chemical products, and the handling and storage of fossil fuels. Electric utility companies generally use or generate a range of pollutants, potentially hazardous products and by-products that are the focus of such regulation. The Authority is also subject to state laws regarding environmental approval and certification of proposed major transmission facilities.

The Clean Air Act Amendments of 1990 (1990 Amendments) limit emissions of sulfur dioxide (SO2), nitrogen oxides (NOx), and other pollutants. The EPA allocates annual SO2 emissions allowances to each of the PSA units based on historical output. NOx emissions are regulated on a regional level through the NOx State Implementation Plan, and are also controlled through allowance allocations. Generating units under the various PPAs and the PSA units are expected to continue to achieve cost effective compliance with these emission control requirements through the use of allocated allowances, capital expenditures, the use of natural gas fuel, and/or the purchase of emission allowances as necessary. Generating units may be required to purchase additional allowances above their unit's allocations, or make other expenditures, based on changes in plant operation, fuel prices, or more restrictive regulations.

In March 2005, the Federal Clean Air Interstate Rule (CAIR) was promulgated, requiring further reductions of SO2 and NOx emissions to reduce ozone and fine particulate matter formation in the eastern United States. The State of New York has adopted rules to carry out this program in which compliance requirements for NOx reduction began in 2009. As part of the Agreement and Waiver with National Grid (the Agreement), National Grid, subject to the terms of the Agreement, is installing additional NOx controls, called Separated Over Fired Air (SOFA), on all the units at Northport and Port Jefferson, to reduce NOx emissions. Current projections of PSA unit operations indicate that the PSA units should be able to comply by using their existing annual allowance allocations and with these new controls. Subsequently, in 2008 the D.C. Circuit Court remanded without vacating EPA's CAIR Rule. In response, on July 6, 2010, EPA proposed the Transport Rule intended to replace CAIR when finalized. This proposed rule, now called the Cross State Air Pollution Rule (CSAPR), was finalized on August 8, 2011, and was to become effective January 1, 2012. However, on December 30, 2011, the D.C. Circuit Court of Appeals stayed the rule and required that the CAIR program continue. The planned SOFA installation on the four Northport and two Port Jefferson units, as well as a planned installation of water injection on additional Holtsville combustion turbines, is expected to make significant reductions to NOx emissions sufficient to comply with any of the revised rulemakings that the EPA is likely to attempt to implement. Compliance with new SO2 limits will likely be achieved with the continued economic use of a high percentage of natural gas, and through fuel switching to lower sulfur fuel oil, if necessary. Based on the current requirements of the stayed CSAPR rule, no additional controls are anticipated. However, additional controls or allowance purchases may be needed depending on the level of reductions ultimately required once the rule is implemented.

In 2009 the DEC, in compliance with the EPA's Regional Haze Rule, issued a State Implementation Plan that specified how reductions in visibility-impairing pollutants would improve visibility in certain designated areas in the Northeastern United States. While the EPA has stated that participation in the Transport Rule will meet requirements, the DEC has proposed its own regulations, including the Best Available Retrofit Technology (BART) requirements. The rule required affected sources to submit a plan to the DEC in October 2010, demonstrating how the sources would comply with the rule. The PSA units' plan documented that SOFA on these six units, as well as the consumption of low sulfur fuel, are BART technologies for these sources. This compliance plan was approved by the DEC and the EPA; the Title V air permits for Northport and E. F. Barrett are currently being modified to include the BART requirements.

EPA is required to regulate Hazardous Air Pollutants from oil and coal fired electric generating units (the Utility MACT Rule or now known as the MATS rule). The EPA finalized the MATS rule on Dec 16, 2011; the PSA units will either not be considered oil fired or will be able to comply with the standard using existing controls with minimal investment.

In 2005, New York State joined the Regional Greenhouse Gas Initiative (RGGI) for the purpose of capping and then reducing greenhouse gas emissions from power plants. New York State adopted its final regulation in 2008 to implement the requirements of RGGI and to auction most of the CO2 allowances comprising the New York share of the regional cap. Regional auctions are being conducted on a quarterly basis. The majority of the power plants which are under long-term contract to the Authority and are in the RGGI region are participating in the auctions, with most having an agreement for cost recovery from the Authority. Several plants are not able to claim recovery of these costs from the Authority, but are still required to comply. The Authority includes such costs as a component of its fuel and purchased power, and as such these costs are subject to recovery as provided under the FPPCA. These costs totaled approximately $10 million and $11 million in 2011 and 2010, respectively.

Section 185 of the Clean Air Act requires states to collect fees from major sources in those areas defined as severe or extreme ozone nonattainment areas that fail to come into compliance with the ozone National Ambient Air Quality Standards (NAAQS) by the dates provided under the Clean Air Act. Based on EPA guidance, it is expected that the fees, initially set at $5,000 per ton of NOx and volatile organic compounds emissions (adjusted annually from 1991 by the consumer price index), will be based on those emissions that exceed 80% of a plant's baseline in year 2007 for sources located in the New York metropolitan area, including on Long Island, or possibly another period representative of a source's normal operations. Several of the PSA units have exceeded the threshold in past years; however, the DEC has not chosen enforcement. Instead, the DEC has submitted to the EPA a demonstration that the area has achieved attainment with the ozone standard and therefore collection of 185 fees is not required. .In response to the increasingly stringent Ozone Ambient Air Quality Standards, the NYS DEC has revised its NOx RACT regulations, significantly reducing the target NOx emission rates for the steam units. This will greatly lower the compliance margin generated by the steam units that allow for the operation of the combustion turbines. The installation of

SOFA on the four Northport and two Port Jefferson units, as well as the installation of water injection on additional Holtsville combustion turbines is expected to make significant reductions that should be sufficient to comply with the new rules.

In 2011, the EPA finalized standards for the emissions of hazardous air pollutants from Reciprocating Internal Combustion Engines (RICE MACT Rule) that affects the East Hampton and Montauk diesels. This standard will require the installation of oxidation catalysts on the diesels by May 2013, which will require modification to the Title V air permits. The DEC required an evaluation of the impact of the diesels on the 1-hr NO2 standard. The analysis determined that in order to ensure that there is not an adverse impact from these facilities; the stacks would need to be raised to ~40 feet. This has been incorporated into the design of the catalysts for East Hampton. LIPA intends to cease operation of the Montauk units by the May 2013 compliance deadline. The EPA has announced its intention to promulgate a New Source Performance Standard (NSPS) for Greenhouse Gases (GHG) from existing electric generating sources. The EPA has stated that they will take a "common sense" approach, based on cost effective and readily available strategies, and that the GHG NSPS will not focus on achieving a single GHG reduction target The EPA has not yet proposed any rules. It is expected that the first rule to be issued will address new sources only. It cannot be estimated at this time what the potential impact of this rulemaking might be.

National Grid and the DEC are parties to a 1998 Consent Order for opacity, for which certain fines are assessed for occasionally exceeding power plant stack opacity limits. Improvements in plant infrastructure and plant operating practices have significantly reduced such occurrences and the amount of fines in recent years.

The Clean Water Act (CWA) requires that electric generating stations hold State Pollutant Discharge Elimination System (SPDES) permits, which reflect water quality considerations for the protection of the environment. Additional capital expenditures will be required as a result of the CWA and DEC requirements to provide Best Technology Available (BTA) to protect marine life from possible impacts from the steam electric generators' cooling water intake systems under Section 316 of the Act. As directed by DEC, National Grid has undertaken studies of the impact of its cooling water intake systems on aquatic resources and submitted engineering alternatives to DEC for mitigating such impacts. National Grid believes that implementing technologies and procedures to reduce cooling water flow during certain periods and the installation of fish "friendly" (e.g., Ristroph type) coarse mesh screens should be sufficient to meet the performance standards established by the DEC.

DEC had issued draft SPDES permits for the Glenwood, Port Jefferson and E.F. Barrett power stations. With respect to Glenwood, the DEC concurred with National Grid that cooling towers are not required and issued a final permit that allows the plant to operate at its projected low capacity factor until 2013. Pursuant to the Eighth Amendment of the PSA, LIPA decided to ramp down its purchases from Glenwood prior to 2013 and National Grid subsequently decided to decommission and demolish the plant. For Port Jefferson, DEC also concurred that cooling towers would not be required and issued a final permit that requires the fish protection technologies as proposed by National Grid at an approximate cost of $18.9 million to be expended by 2015.

For E.F. Barrett, DEC proposed cooling towers in the draft permit. National Grid filed comments on various aspects of the draft permit, including the selection of cooling towers as Best Technology Available and the need for an environmental review. DEC subsequently withdrew the draft permit to allow for a full environmental review of the potential impacts of cooling towers under the State Environmental Quality Review Act. Commencement of this review is pending. DEC has not yet issued draft permits for Northport and Far Rockaway. Pursuant to the Eight Amendment, purchases from Far Rockaway will be ramped down similar to Glenwood; therefore any requirements are expected to be minimal.

The final nature and extent of any fish protection expenditures at E.F. Barrett and Northport cannot be fully determined until ongoing analyses of the impacts and mitigation options are completed by DEC, and permit conditions are negotiated, subjected to public comment, and possibly litigated. At this time, reasonably possible estimates for compliance upgrades proposed by National Grid for Port Jefferson, Barrett and Northport covering a range of potential mitigation options, could be between $80 and $100 million. While detailed cost estimates have not yet been prepared, if cooling towers are required at E.F. Barrett or Northport, preliminary estimates indicate that costs could be approximately $120 million at Barrett and on the order of $260 million to $400 million at Northport, (plus additional maintenance and fuel costs) which may be passed through to the Authority depending on the timing of these requirements and the exercise of certain options that the Authority has under the PSA.

Recent changes to the SPCC regulations (40 CFR 112) effectively require the internal inspections of No. 6 oil tanks on a frequency and in a manner that is based on the criteria of the American Petroleum Institute's guidelines. Over the past ten years, eight tanks were internally inspected and no significant corrosion was found. Over the next 15 years, the remaining ten additional tanks will be scheduled for internal inspections at an estimated cost of $9 million which may be passed through to the Authority depending on the timing of these requirements and the exercise of certain options that the Authority has under the PSA. Any subsequent repairs that may be indicated by these inspections cannot be estimated at this time. The Authority does not believe that its share of these costs will have a material adverse effect on its financial position, cash flows or results of operations.

KPMG LLP
345 Park Avenue
New York, NY 10154

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 the financial statements of Long Island Power Authority (the Authority) as of and for the year ended December 31,2011, and have issued our report thereon dated March 29, 2012. We conducted our audit 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.

Internal Control over Financial Reporting

Long Island Power Authority is responsible for establishing and maintaining effective internal control over financial reporting. In planning and performing our audit, we considered the Authority's internal control over financial reporting as a basis for designing our auditing procedures for the purpose of expressing our opinion on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of the Authority's internal control over financial reporting. Accordingly, we do not express an opinion on the effectiveness of the Authority's internal control over financial reporting.

A deficiency in internal control over financial reporting 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 combination of deficiencies, in internal control over financial reporting, 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.

Our consideration of internal control over financial reporting was for the limited purpose described in the preceding paragraphs and was not designed to identify all deficiencies in internal control over financial reporting that might be significant deficiencies or material weaknesses and therefore, there can be no assurance that all deficiencies, significant deficiencies, or material weaknesses have been identified. We did not identify any deficiencies in internal control over financial reporting that we consider to be material weaknesses, as defined above.

Compliance and Other Matters

As part of obtaining reasonable assurance about whether the Authority's financial statements are free of 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 did not disclose instances of noncompliance or other matters that are required to be reported under *Government Auditing Standards.*

KPMG LLP is a Delaware limited liability partnership, the U.S. member firm of KPMG International Cooperative ("KPMG International"), a Swiss entity.

This report is intended solely for the information and use of management, the Board of Trustees, others within the Authority, and is not intended to be and should not be used by anyone other than these specified parties.

KPMG LLP

March 29, 2012