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

Basic Financial Statements

December 31, 2009 and 2008

(With Independent Auditors' Report Thereon)

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KPMG LLP
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Independent Auditors' Report

The Board of Trustees
Long Island Power Authority:

We have audited the balance sheets, statements of revenues, expenses, and changes in net assets, and statements of cash flows of the Long Island Power Authority (Authority), a component unit of the State of New York, as of and for the years then ended December 31, 2009 and 2008, 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, 2009 and 2008, 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 26, 2010, 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 26, 2010

Overview of the Financial Statements

This report consists of three parts: management's discussion and analysis, 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) that do not conflict with GASB pronouncements.

The following is a summary of the Authority's financial information for 2009, 2008, and 2007 (amounts in thousands):

Balance Sheet Summary

	December 31, 2009	December 31, 2008	December 31, 2007
Assets:			
Current assets:			
Cash, cash equivalents and investments	$ 495,547	257,720	814,412
Other current assets	569,655	725,269	705,216
Noncurrent assets:			
Utility plant, net	6,459,718	5,725,010	5,320,740
Promissory notes receivable	155,425	155,425	155,425
Nonutility property and other investments	74,679	71,753	70,979
Deferred charges and long-term receivables	322,754	584,360	235,657
Regulatory assets	929,223	1,097,230	780,867
Acquisition adjustment, net	2,629,216	2,741,897	2,854,578
Total assets	$ 11,636,217	11,358,664	10,937,874
Liabilities and net assets:			
Regulatory liability	$ 164,520	2,483	269,476
Other current liabilities	1,150,061	1,196,538	1,215,244
Noncurrent liabilities:			
Long-term debt	6,407,436	6,394,364	6,402,713
Capital lease obligation	2,970,126	2,369,168	2,130,236
Other noncurrent liabilities	140,291	310,187	130,794
Deferred credits	474,079	796,746	526,575
Total liabilities	11,306,513	11,069,486	10,675,038
Net assets (deficit):			
Capital assets net of related debt	(171,412)	(56,269)	(190,510)
Restricted	46,340	229,285	—
Unrestricted	454,776	116,162	453,346
Total net assets	329,704	289,178	262,836
Total liabilities and net assets	$ 11,636,217	11,358,664	10,937,874

Summary of Revenues, Expenses, and Changes in Net Assets

	Year ended December 31,		
	2009	**2008**	**2007**
Electric revenue	$ 3,312,160	3,751,610	3,626,135
Operating expenses:			
Operations – fuel and purchased power	1,566,005	2,164,658	1,922,075
Operations and maintenance	864,576	785,342	847,963
General and administrative	40,153	31,347	37,978
Depreciation and amortization	254,944	246,919	245,632
Payments in lieu of taxes	249,652	239,659	231,490
Prior service cost – OPEB's	—	—	10,912
Total operating expenses	2,975,330	3,467,925	3,296,050
Operating income	336,830	283,685	330,085
Other income, net	33,519	69,862	82,374
Interest charges	(329,823)	(323,365)	(319,413)
Change in net assets before extraordinary loss	40,526	30,182	93,046
Extraordinary loss on early extinguishment of debt	—	(3,840)	—
Change in net assets	40,526	26,342	93,046
Net assets – beginning of year	289,178	262,836	169,790
Net assets – end of year	$ 329,704	289,178	262,836

Excess of Revenues over Expenses

The revenues in excess of expenses for the years ended December 31, 2009, 2008 and 2007 totaled approximately $41 million, $26 million and $93 million, respectively.

Revenues

Revenue for the twelve months ended December 31, 2009 decreased approximately $439 million when compared to the similar period of 2008. This decrease is primarily attributable to lower recoveries of power supply costs totaling $369 million, the negative effects of weather totaling $34 million, and lower average customer usage totaling approximately $36 million. Despite the reduction in the FPPCA rate effective May 1, 2009 and the one-time bill credits issued totaling approximately $143 million, approximately $164 million of power supply recovery revenues were collected that exceeded actual fuel and purchased power supply costs incurred. This over-recovery has been deferred for return to the customer through the reduced FPPCA rate effective January 1, 2010, and will be further adjusted throughout the year if needed.

Revenue for the twelve months ended December 31, 2008 increased approximately $125 million (which included an approximate $14 million adjustment related to a potential settlement with a commercial customer) when compared to the similar period of 2007. This increase is primarily attributable to the higher recoveries of power supply costs revenues totaling approximately $150 million partially offset by the sales mix and lower average customer usage, (primarily in the Commercial & Industrial segment), totaling approximately $12 million and the negative effects of weather totaling approximately $13 million.

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, 2009, fuel and purchased power costs decreased $599 million. LIPA experienced lower commodity costs of $611 million (offset by derivative losses of $144 million), lower consumption due to sales volumes totaling $68 million and the higher amortization of customer bill credits that reduced expense by an additional $64 million when compared to 2008.

For the year ended December 31, 2008, fuel and purchased power expense increased approximately $243 million as a result of an increase in the net commodity costs of approximately $511 million partially offset by derivative gains of $204 million, the impact of lower sales volumes of approximately $28 million, and the amortization of customer bill credits that reduced expense by an additional $36 million.

Operations and Maintenance Expense (O&M)

Operations and maintenance (O&M) expense increased $79 million due to higher Power Supply Agreement (PSA) capacity charge billings totaling $39 million, higher clean energy program costs totaling $25 million, higher storm restoration costs totaling $13 million, higher charge-offs of bad debt accounts totaling $9 million and higher Nine Mile Point 2 costs totaling $2 million. These increases were partially offset by $4 million due to the scheduled increase in the Management Services Agreement (MSA) synergy savings credits from National Grid, lower asset retirement accretion expense of $3 million due to a revised Nine Mile Point 2 decommissioning study and $2 million due to the elimination of postage paid envelopes.

O&M expense for the year ended December 31, 2008, decreased by approximately $63 million primarily attributable to a $34 million decrease in costs associated with the ongoing funding of certain KeySpan electric service employee benefit programs, approximately $9 million of synergy savings credits received from National Grid, lower Management Services Agreement costs totaling approximately $8 million, lower clean energy program costs totaling approximately $9 million, lower storm restoration costs totaling approximately $3 million, lower Nine Mile Point 2 operating costs totaling approximately $3 million and other various items totaling approximately $1 million. These decreases were partially offset by higher Power Supply Agreement (PSA) costs totaling approximately $4 million.

General and Administrative Expenses (G&A)

General and administrative expenses for the year ended December 31, 2009 increased by $9 million partially attributable to an adjustment in 2008 related to injuries and damages settlements that resulted in a $3 million credit in 2008. Also contributing to the increase is higher employee benefit costs totaling $1 million and higher advertising and consulting costs totaling $5 million due to various new projects.

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G&A expenses for the year ended December 31, 2008 decreased approximately $7 million as a result of reducing the reserve for injuries and damages by approximately $3 million, lower employee benefit costs totaling approximately $2 million and the use of deferred settlement amounts to offset consulting fees totaling approximately $2 million.

Depreciation and Amortization

For the years ended December 31, 2009 and 2008, depreciation and amortization increased approximately $8 million and $1 million, respectively, due to higher utility plant balances.

Payments in Lieu of Taxes

For the years ended December 31, 2009 and 2008, payments in lieu of taxes (PILOTs) increased approximately $10 million and $8 million, respectively, due to higher property taxes on the transmission and distribution assets.

Prior Service Cost – OPEBs

In 2007, the Authority adopted the provisions of GASB No. 45, which, in addition to requiring the recognition of a current period expense for providing health benefits to employees upon their retirement, also required the recognition of amounts incurred in the periods prior to the adoption of this pronouncement. The prior years' service costs related to this adoption totaled approximately $11 million.

For 2009 and 2008, the current period expense related to providing health benefits to employees upon their retirement is included in G&A.

Other Income, Net

Other income decreased approximately $36 million for the year ended December 31, 2009, when compared to the year ended December 31, 2008, as a result of lower investment earnings totaling $19 million due to lower average cash balances and lower interest rates, lower sales of emissions allowance credits totaling $4 million and higher miscellaneous expenses totaling $6 million (due to the Board approved costs related to community benefits packages). In addition, in 2008 LIPA recognized $7 million of nonrecurring income related to an interest rate swap that was terminated.

Other income decreased approximately $13 million for the year ended December 31, 2008 when compared to the year ended December 31, 2007 as a result of lower investment earnings totaling approximately $15 million and lower gains on the sale of unneeded emissions allowance credits totaling approximately $11 million. Partially offsetting these lower income items was approximately $7 million of income related to the interest rate swap that was terminated in 2008 and an approximate $6 million decrease related to the community benefits package associated with the Caithness generating station incurred in 2007.

Interest Charges and Credits

For the year ended December 31, 2009, total interest charges increased approximately $6 million due to higher debt balances outstanding and higher interest rates on the fixed rate debt which refunded variable rate securities.

For the year ended December 31, 2008, total interest charges increased approximately $4 million when compared to 2007 due to higher interest rates on variable rate debt, the restructuring in the fourth quarter of a portion of the

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insured variable rate debt to higher cost fixed rate debt and increased interest costs associated with holding counterparty collateral.

Extraordinary Loss on Early Extinguishment of Debt

In March 2008, the Authority redeemed $200 million of its insured variable rate Electric System General Revenue Bonds to lower the risks associated with the marketability of LIPA's variable rate debt portfolio. The Authority used cash on hand to redeem these securities. The Authority had deferred charges totaling approximately $4 million associated with these bonds that were recognized as an extraordinary loss on the early extinguishment of debt.

Cash, Cash Equivalents, and Investments

The Authority's cash, cash equivalents, and investments totaled approximately $496 million, $258 million, and $814 million at December 31, 2009, 2008, and 2007, respectively. The increase from 2008 to 2009 is due to the fuel and purchased power supply costs recovered in excess of that incurred and the lower counterparty collateral postings required. The decrease from 2007 to 2008 is due to increased fuel and purchased power costs, required collateral postings with various counterparties, the return of prior year excess power supply costs to the ratepayer and the redemption of debt with cash on hand. 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, 2009 and 2008. At December 31, 2007, $100 million of commercial paper notes were outstanding.

Capital Assets

The Authority continued its investment in transmission and distribution (T&D) upgrades to manage reliability and to enhance capacity needed to meet growing customer demands. For the years ended December 31, 2009 and 2008, capital improvements to the T&D system totaled approximately $229 million and approximately $267 million, respectively. These improvements included interconnection equipment necessary to connect newly installed capacity to the system, the replacement or upgrade of transformer banks and circuit breakers, new substations, enhanced transmission lines and upgraded command and control equipment.

Regulatory Assets

Regulatory assets decreased approximately $168 million from December 31, 2008 to December 31, 2009. The decrease is the result of: (i) the negative mark-to-market valuation on the Authority's fuel and purchased power derivatives totaling approximately $180 million from $357 million in 2008, (ii) the recovery of the 2003 deferred excess fuel and purchased power costs totaling approximately $35 million, scheduled to be recovered over a ten-year period which began January 1, 2004, in accordance with the Authority's tariff, and (iii) the scheduled recovery of approximately $36 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 basic financial statements). These decreases were partially offset by: (i) carrying charges on the Shoreham Property Tax Settlement Agreement related credits totaling approximately $31 million for the year, (ii) the deferral of the 2009 special assessment paid to New York State (NYS) totaling $37 million; (since LIPA's rates did not include the recovery until 2010, the 2009 assessment was deferred to be collected ratably from ratepayers over the next four years) and (iii) approximately $12 million of incremental costs associated with the Southampton Visual Benefits Assessment (VBA) Agreement between LIPA and the Town of Southampton (Town). In May 2008, LIPA and the Town reached an agreement allowing LIPA to collect over a 20-year period any incremental costs (plus interest) associated with undergrounding a transmission line.

Regulatory assets increased approximately $316 million from December 31, 2007 to December 31, 2008. The increase is the result of: (i) the negative mark-to-market valuation on the Authority's fuel and purchased power derivatives totaling approximately $357 million, and (ii) carrying charges on the Shoreham Property Tax Settlement Agreement related credits totaling approximately $32 million. These increases were partially offset by: (i) the recovery of the 2003 deferred excess fuel and purchased power costs totaling approximately $36 million, scheduled to be recovered over a ten-year period which began January 1, 2004, in accordance with the Authority's tariff, and (ii) the scheduled recovery of approximately $37 million related to the Shoreham Property Tax Settlement Agreement through the Shoreham surcharge (as discussed in greater detail in note 3 to the basic financial statements).

Regulatory Liabilities

For the year ended December 31, 2009, the regulatory liabilities increased by approximately $162 million resulting primarily from the recovery of fuel and purchased power supply costs recovered in excess of costs incurred which will be returned to customers through reductions in the FPPCA in 2010.

For the year ended December 31, 2008, the regulatory liabilities decreased by approximately $267 million resulting from: (i) the return of 2007 excess recovery of fuel and purchased power supply costs which totaled approximately $112 million and; (ii) the net change in the mark-to-market on the Authority's fuel and purchased power derivatives which totaled approximately $155 million at December 31, 2007. At December 31, 2008, the Authority had a mark-to-market loss on its fuel derivatives, which was recorded in regulatory assets.

Debt

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

	Debt Balance at December 31,		
	2009	2008	2007
General Revenue Bonds	$ 5,924,664	5,722,633	5,791,239
Subordinated Revenue Bonds	576,705	785,825	879,725
Commercial Paper Notes	200,000	200,000	100,000
NYSERDA Notes	155,420	155,420	155,420
	$ 6,856,789	6,863,878	6,926,384

During 2009, debt decreased approximately $7 million resulting from scheduled maturities of approximately $242 million and the refunding of $231 million outstanding insured variable rate debt. This was partially offset by: i) the issuance of Electric System General Revenue Bonds Series 2009A totaling approximately $436 million which was used for the purpose of the refunding discussed and the remainder used to finance the Authority's on going capital improvements program; and ii) the accretion of the capital appreciation bonds totaling approximately $30 million.

During 2008, debt decreased approximately $63 million resulting from scheduled maturities of approximately $227 million and partially offset by: i) the issuance of Electric System General Revenue Bonds Series 2008A and Series 2008B totaling approximately $754 million for the purpose of refunding $719 million of certain outstanding insured variable rate debt and with the remainder used to help finance the Authority's on going capital improvements program; ii) the issuance of additional Commercial Paper Notes totaling $100 million; and iii) the accretion of the capital appreciation bonds totaling approximately $29 million.

For a full discussion on the Authority's refunding activities during 2009 and 2008, see note 9 to the basic financial statements.

Risk Management

The Authority is routinely exposed to commodity and interest rate risk. In order 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 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 FPPCA and mitigate the exposures in line with the Authority's identified level of risk tolerance. The Authority actively manages the program in both upward and downward trending markets and adjusts its positions as necessary to mitigate the impact of potentially unfavorable market movements. At December 31, 2009 and 2008, the Authority had posted approximately $46 million and $229 million, respectively, of collateral to its counterparties in connection with its energy commodity hedge positions. At December 31, 2007, the Authority held $2.9 million of counterparty collateral. No collateral was held by or posted by the Authority with respect to its interest rate derivatives.

In accordance with FASB ASC 815 *Derivatives and Hedging* (previously SFAS No. 133, *Accounting for Derivatives and Hedging Activities*, as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities* and SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*), the Authority records its derivatives at fair value and records unrealized gains and losses. For a further discussion on these matters, see note 3 of the basic financial statements.

Fuel and purchased power transactions – For the year ended December 31, 2009, the Authority had realized losses of $106 million and recognized $38 million of option premium amortization which increased fuel and purchased power costs by $144 million. LIPA also recorded an unrealized loss on commodity derivatives of approximately $180 million, reflecting the negative mark-to-market on LIPA's fuel derivative positions. For the year ended December 31, 2008, the Authority had realized gains totaling approximately $204 million, net of related option premium amortization, which reduced fuel and purchased power costs and recorded an unrealized loss (negative mark-to market) on commodity derivatives of approximately $357 million.

Interest rate transactions – At December 31, 2009 and 2008, the Authority recorded net unrealized fair value losses of approximately $232 million and $498 million, respectively, which includes unamortized up front premiums totaling approximately $106 million and $111 million, respectively, related to certain of these derivative transactions. The up front premiums are being amortized over the life of the underlying debt as interest rate modifiers. Any gains or losses resulting from changes in the mark-to-market valuations are deferred, and will be recognized when realized consistent with FASB ASC 980 *Regulated Operations* (previously SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*).

Power Supply

The Authority has entered into numerous agreements for capacity and energy necessary to continue to satisfy the energy demand of Long Island, 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 basic 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):

	Investment ratings		
	Moody's	**S&P**	**Fitch**
Senior Lien debt	A3	A-	A-

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, 2009 and 2008

(Dollars in thousands)

Assets		**2009**	**2008**
Current assets:			
Cash and cash equivalents	$	371,264	225,158
Investments		124,283	32,562
Counterparty collateral – posted by the Authority		46,340	229,285
Accounts receivable (net of allowance for doubtful accounts of $21,000 and $19,485, respectively)		246,670	275,755
Other accounts receivable		104,872	49,503
Fuel inventory		156,029	131,286
Material and supplies inventory		8,276	7,282
Interest receivable		28	275
Prepayments and other current assets		7,440	31,883
Total current assets		1,065,202	982,989
Noncurrent assets:			
Utility plant and property and equipment, net		6,459,718	5,725,010
Promissory notes receivable – KeySpan Energy		155,425	155,425
Nonutility property and other investments		74,679	71,753
Other long term receivables		72,657	80,276
Deferred unrealized loss – financial derivatives		125,910	386,462
Deferred charges		124,187	117,622
Regulatory assets:			
New York State assessment		37,040	—
Southampton visual benefit assessment		12,070	—
Shoreham property tax settlement		552,929	557,470
Fuel and purchased power costs recoverable		327,184	539,760
Acquisition adjustment (net of accumulated amortization of $1,466,296 and $1,353,615, respectively)		2,629,216	2,741,897
Total noncurrent assets		10,571,015	10,375,675
Total assets	$	11,636,217	11,358,664

See accompanying notes to basic financial statements.

Liabilities and Net Assets		2009	2008
Current liabilities:			
Short-term debt	$	200,000	200,000
Current maturities of long-term debt		224,960	241,370
Current portion of capital lease obligation		127,953	102,844
Accounts payable and accrued expenses		362,384	366,897
Regulatory liability – fuel and purchased power costs		164,520	2,483
Fuel derivatives		112,928	167,532
Accrued payments in lieu of taxes		41,091	37,708
Accrued interest		52,642	52,138
Customer deposits		28,103	28,049
Total current liabilities		1,314,581	1,199,021
Noncurrent liabilities:			
Long-term debt		6,407,436	6,394,364
Capital lease obligation		2,970,126	2,369,168
Fuel derivatives		66,611	189,599
Asset retirement obligation		73,680	92,558
Total noncurrent liabilities		9,517,853	9,045,689
Deferred credits – financial derivatives		231,576	497,674
Deferred credits – other		203,637	299,072
Claims and damages		38,866	28,030
Commitments and contingencies (notes 12 and 13)			
Net assets (deficit):			
Invested in capital assets net of related debt		(171,412)	(56,269)
Restricted		46,340	229,285
Unrestricted		454,776	116,162
Total net assets		329,704	289,178
Total liabilities and net assets	$	11,636,217	11,358,664

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, 2009 and 2008

(Dollars in thousands)

		2009	2008
Operating revenues – electric sales	$	3,312,160	3,751,610
Operating expenses:			
Operations – fuel and purchased power		1,566,005	2,164,658
Operations and maintenance		864,576	785,342
General and administrative		40,153	31,347
Depreciation and amortization		254,944	246,919
Payments in lieu of taxes		249,652	239,659
Total operating expenses		2,975,330	3,467,925
Operating income		336,830	283,685
Nonoperating revenues and expenses:			
Other income, net:			
Investing income		5,029	24,443
Carrying charges on regulatory asset		31,860	31,829
Other		(3,370)	13,590
Total other income, net		33,519	69,862
Interest charges and (credits):			
Interest on long-term debt, net		328,028	316,424
Other interest		10,257	15,291
Allowance for borrowed funds used during construction		(8,462)	(8,350)
Total interest charges		329,823	323,365
Total nonoperating revenues and expenses		(296,304)	(253,503)
Change in net assets before extraordinary loss		40,526	30,182
Extraordinary loss on early extinguishment of debt		—	(3,840)
Change in net assets		40,526	26,342
Total net assets, beginning of year		289,178	262,836
Total net assets, end of year	$	329,704	289,178

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, 2009 and 2008

(Dollars in thousands)

		2009	2008
Cash flows from operating activities:			
Received from customers for system sales, net of refunds	$	3,528,777	3,652,883
KeySpan/National Grid Settlement		—	1,587
Other operating revenues received		89,742	34,265
Paid to suppliers and employees:			
Operations and maintenance		(982,774)	(850,003)
Fuel and purchased power		(1,604,744)	(2,122,236)
Payments in lieu of taxes		(351,769)	(341,260)
Collateral on fuel derivative transactions, net		182,945	(232,185)
Net cash provided by operating activities		862,177	143,051
Investing activities:			
Sales of investment securities		34,620	815,596
Purchase of investment securities		(126,234)	(552,602)
Fair value adjustment – short term securities		93	101
Realized gains on short term securities		(201)	(7,776)
Earnings received on investments		2,783	20,341
Other		(2,453)	4,714
Net cash (used in) provided by investing activities		(91,392)	280,374
Cash flows from capital and related financing activities:			
Capital and nuclear fuel expenditures		(282,578)	(297,312)
Proceeds from promissory note		8,075	8,075
Proceeds from the issuance of bonds, net of discount/premium		445,045	831,037
Bond issuance costs		(3,112)	(14,899)
Interest paid, net		(319,639)	(306,229)
Redemption of long-term debt		(472,470)	(945,470)
Net cash used in capital and related financing activities		(624,679)	(724,798)
Net increase (decrease) in cash and cash equivalents		146,106	(301,373)
Cash and cash equivalents at beginning of year		225,158	526,531
Cash and cash equivalents at end of year	$	371,264	225,158
Reconciliation to net cash provided by operating activities:			
Operating income	$	336,830	283,685
Adjustments to reconcile operating income to net cash provided by operating activities:			
Depreciation and amortization		254,944	246,919
Nuclear fuel burned		6,690	5,906
Shoreham surcharges (credits), net		35,923	36,570
Provision for claims and damages		50,683	37,584
Accretion of asset retirement obligation		1,865	5,468
Amortization of settlement benefits to ratepayers		(100,000)	(36,000)
Other, net		(1,730)	(1,581)
Changes in operating assets and liabilities:			
Accounts receivable, net		(12,334)	59,231
Regulatory asset – New York State assessment		(37,040)	—
Fuel and material and supplies inventory		(25,737)	11,358
Deferred fuel and purchased power costs		197,021	(75,814)
Counterparty collateral		182,945	(232,185)
Claims, damages and storm restoration		(39,847)	(48,807)
Accounts payable, accrued expenses and other		11,964	(149,283)
Net cash provided by operating activities	$	862,177	143,051

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 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. To assist the Authority in meeting these responsibilities, the Authority contracted with KeySpan Energy Corporation (KeySpan), a wholly owned subsidiary of National Grid plc, to provide: operations and management services related to the transmission and distribution system through a Management Services Agreement (MSA); capacity and energy from the fossil fired generating plants of KeySpan, through a Power Supply Agreement (PSA); and, energy and fuel management services through an Energy Management Agreement (EMA) (collectively; the Operating Agreements). Through these contracts, the Authority pays KeySpan directly for these services and KeySpan, in turn, pays the salaries of its employees and fees of its contractors and suppliers. In 2009 and 2008, the Authority paid to KeySpan approximately $2 billion each year under the 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 2006, the Authority entered into agreements with certain of the KeySpan subsidiary companies to amend the MSA and certain other Operating Agreements. The Amended and Restated MSA (i) provides a simpler "fee for service" contract, (ii) establishes 18 service level metrics which KeySpan must achieve or be subject to monetary penalties and (iii) has a term that expires on December 31, 2013.

Certain services provided for under the EMA expired on December 31, 2009. Through a competitive procurement process, the Authority has selected two new providers of those services. Both contracts commenced on January 1, 2010 for an initial five-year period and are subject to an extension for a period of five years at the Authority's option. Both contracts have been approved by the New York State Comptroller and the Attorney General.

The Authority had also entered into option agreements with KeySpan Generation LLC (GENCO) which provided the Authority with an option to acquire the E.F. Barrett and/or the Far Rockaway plants for book value at the time of sale (the Purchase Option Agreement). The Purchase Option Agreement was set to expire on May 31, 2008; however, the expiration date was extended to December 31, 2008 and further extended to September 30, 2009. The Authority notified National Grid that it will not exercise its rights under this agreement. National Grid also granted the Authority options to purchase, at 1.25 times book value at the time of sale, the combustion turbines at the Shoreham and Wading River sites. The Authority allowed the purchase option for the Shoreham and Wading River sites to expire on December 31, 2008. The Authority also obtained 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).

In consideration for the Authority's waiver of its rights under the change of control provisions in the Operating Agreements as a result of the National Grid acquisition of KeySpan in 2007, the Authority and National Grid reached an agreement (the Agreement and Waiver). Under the Agreement and Waiver, National Grid agreed to pay the Authority approximately $91 million over a period of seven years representing the Authority's guaranteed share of the synergy savings resulting from the National Grid acquisition of KeySpan. The Authority recorded the net present value (using a 7.8% interest rate) totaling approximately $68 million. As of December 31, 2009, the Authority has a current receivable of approximately $29 million and a noncurrent other receivable of approximately $39 million remaining outstanding.

The Authority and LIPA are also parties to an Administrative Services Agreement, which describes the terms and conditions under which the Authority provides personnel, personnel-related services, and other services necessary for LIPA to provide service to its customers. As compensation to the Authority for the services described above, the Authority charges LIPA a monthly management fee equal to the costs incurred by the Authority in order to perform its obligations under the Administrative Services Agreement.

(3) Summary of Significant Accounting Policies

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) 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.

Accounting for the Effects of Rate Regulation

The Authority is subject to the provisions of FASB ASC 980 *Regulated Operations* (previously SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*). 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 and 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: (1) 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; (2) the regulated rates must be designed to recover the specific enterprise's costs of providing the regulated services; and (3) 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.

If the Authority had been unable to continue to apply the provisions of FASB ASC 980 *Regulated Operations*, as of December 31, 2009, the Authority estimates that approximately $163 million of net recoverable fuel and purchased power costs, approximately $126 million of net unrealized deferred losses on the Authority's financial derivative transactions, approximately $37 million deferred assessment costs, and the acquisition adjustment totaling approximately $2.6 billion would be considered for impairment.

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. See note 8 for a further discussion.

Counterparty Collateral

Whenever the Authority enters into a transaction to mitigate risk, it becomes exposed to an event of nonperformance by the counterparty; however, to limit its exposure to such risk, the Authority will only enter into derivative transactions with counterparties that have a credit rating of "investment grade" or better. The Authority and its counterparties require collateral posting for mark-to-market valuations that exceed established credit limits. At December 31, 2009, the Authority was required to post approximately $46 million of collateral to various counterparties, which is reflected as a current asset and is considered a restricted net asset. At December 31, 2008, the Authority was required to post approximately $229 million of collateral to various counterparties, which is also reflected as a current asset and is considered a restricted net asset.

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. See note 6 for further discussion.

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

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.

Fuel Derivatives

The Authority uses derivative instruments through its risk management program in an attempt to protect its customers from market price fluctuations for the purchase of fuel oil, natural gas and electricity. The 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 FPPCA and mitigate the exposures in line with the Authority's identified level of risk tolerance. The Authority actively manages the program in both upward and downward trending markets and adjusts its positions as necessary to mitigate the impact of changing market trends.

These instruments are recorded at fair value, see note 4 for further discussion. Any unrealized gains or losses are deferred until realized, in accordance with the provisions of the fuel and purchased power cost adjustment (FPPCA).

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.

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, 2009 and 2008, approximately $155 million remained outstanding, respectively. The fair market value of the note at December 31, 2009 and 2008 is approximately $156 million and $153 million, respectively. 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.

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, 2009 and 2008, the value of the Trusts was approximately $75 million and $72 million, respectively.

Other Long-Term Receivables

This represents the net present value of synergy savings credits due from National Grid resulting from their purchase of KeySpan as discussed in note 2. The Authority also recorded 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.

Deferred Unrealized Loss – Financial Derivatives

The Authority uses derivative instruments to manage the cash flow impact of interest rate changes on its customer's, net assets and cash flows. Under the provisions of FASB ASC 815, *Derivatives and Hedging* (previously SFAS No. 133, *Accounting for Derivatives and Hedging Activities*, as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities* and SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*), the Authority is required to recognize the fair value of all derivative instruments as either an asset or liability on the balance sheet with an offsetting gain or loss also recognized on the balance sheet. In accordance with FASB ASC 820 *Fair Value Measurements and Disclosures* (previously SFAS No. 157, *Fair Value Measurements*), the fair market values of the derivatives are provided by an independent third party. These standards permit the deferral of hedge gains and losses to Other Comprehensive Income, under specific hedge accounting provisions, until the hedged transaction is realized. However, the Authority is a governmental agency and, therefore, its financial statements are prepared in accordance with the provisions of the Governmental Accounting Standards Board, which do not provide for Other Comprehensive Income. However, as the Authority is subject to the provisions of FASB ASC 980 *Regulated Operations*, all such gains and losses are deferred until realized, which corresponds to the period they are recovered in rates.

Deferred Charges

Deferred charges consists primarily of 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, and certain 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 related Power Purchase Agreement). Also recorded as a deferred charge are costs related to the transition to two new service providers who, after competitive solicitation were selected to provide support services to LIPA's fuel hedging program for a period of five years.

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, 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, 2009 and 2008 was approximately $553 million and $557 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 totaling approximately $233 million.

Southampton Visual Benefit Assessment

The Authority has recorded the incremental costs (approximately $12 million) 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 20 years.

New York State Temporary Energy and Utility Conservation Assessment

As a result an amendment to the Public Service Law effective April 1, 2009, utilities in the State are 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 of $37 million has been deferred and will be collected ratably from customers over the next four years.

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, up to 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 Authority would exceed or fail to meet its 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 a 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, 2009 and 2008, the uncollected balance of this deferral totaled approximately $148 million and $183 million, respectively.

In addition, the Authority uses derivative instruments to attempt to protect its net assets and cash flows from significant price fluctuations for the purchase of fuel oil, natural gas and electricity. As the Authority is subject to the provisions of FASB ASC 980 *Regulated Operations*, unrealized gains and losses on such derivatives are deferred until realized.

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.

Fair Values of Financial Instruments

Effective January 1, 2008, the Authority adopted FASB ASC 820, *Fair Value Measurements and Disclosures Prospectively*, for applicable financial instruments that are measured at fair value on a recurring basis. For the Authority, FASB ASC 820 *Fair Value Measurements and Disclosures* establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements and does not require any new fair value measurements. See note 4 for a further discussion on fair value of financial instruments.

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 (previously Emerging Issues Task Force No. 01-08, *Determining Whether an Arrangement Contains a Lease* and previously SFAS No. 13, *Accounting for 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 discussed above, 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 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.

Deferred Credits

Deferred credits primarily represents amounts received from KeySpan/National Grid (Grid benefits) as a result of certain renegotiated and other agreements with the Authority. The Authority's management implemented a plan to provide long-term customer benefits including: the creation of a fund for low-income seniors; and funding certain energy-related initiatives. The Board authorized $100 million of these Grid benefits to be used during 2009 as a reduction to the amounts recoverable from customers through the FPPCA, and provided for the establishment of a $10 million fund to assist qualifying low income senior citizens customers with a one-time $200 bill credit for electric service.

Deferred Credits – Financial Derivatives

Represents the net amount that the Authority would be required to pay in order to terminate these financial derivative instruments as of December 31, 2009 and 2008. The amount shown includes the unamortized balance of cash premiums received at the time of entering into these instruments. The Authority is amortizing such premiums ratably over the life of the instrument.

Claims and Damages

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

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. All other revenue not meeting this definition 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, 2009 and 2008, the Authority received approximately 52% of its revenues from residential sales, 43% from sales to commercial and industrial customers, and the balance from sales to public authorities and municipalities.

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. The rates are determined by age-life studies performed on depreciable properties. The average composite depreciation rate is 2.85% and 2.83% for December 31, 2009 and 2008, 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		Capitalization threshold
Generation – nuclear	39 – 46 years	$	200
Transmission and distribution	20 – 48 years		200
Common	4 – 41 years		200
Nuclear fuel in process and in reactor	6 years		—
Generation assets under capital lease	10 – 25 years		—

Payments-in-Lieu-of-Taxes

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

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 5.19% and 4.49% for the years ended December 31, 2009 and 2008, respectively.

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.

Regulatory Liability – Fuel and Purchased Power Costs

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

(Continued)

recognized as regulatory liabilities. In addition, in accordance with the FPPCA, unrealized mark-to-market gains on commodity derivatives are considered regulatory liabilities and returned to the customer in the period realized.

Asset Retirement Obligation

The Authority adopted FASB ASC 410 *Asset Retirement and Environment Obligations* (previously SFAS No. 143, *Accounting for Asset Retirement Obligations*). An Asset Retirement Obligation (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 obligation is offset by the capitalization of the asset which is included in "Utility plant and property and equipment, net". As of December 31, 2009 and 2008, the NMP2 asset retirement obligation totaled approximately $68 million and $87 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 discuss 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, 2009 and 2008, the asset retirement obligation for the Authority's utility assets totaled approximately $6 million.

A summary of the asset retirement obligation activity of the Authority for the years ended December 31, 2009 and 2008 is included below (amount in thousands):

		2009	2008
Asset retirement obligation:			
Beginning balance	$	92,558	91,541
Liabilities incurred		—	(733)
Changes in fair market value of decommissioning fund		977	(3,718)
Change in estimate		(22,584)	—
Accretion expense		2,729	5,468
Balance at December 31	$	73,680	92,558

Long-Lived Assets

Long-lived assets, such as property, plant, and equipment, 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. The service utility of a capital asset is the usable capacity that at acquisition was expected to be used to provide service. An 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.

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.

Reclassifications

Certain prior year amounts have been reclassified in the financial statements to conform to the current year presentation. Regulatory items previously recorded as credits within the fuel and purchased power expenses have been reclassed to revenue. This has no impact on change in net assets.

Adoption of New Accounting Standards

Effective September 15, 2009, the Authority adopted the requirements of FASB ASC 105, *U.S. GAAP Codification of Accounting Standards* (previously SFAS No. 168, *FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*). FASB ASC 105 is effective for financial statements issued for interim and annual periods ending after September 15, 2009 and establishes the ASC as the source of authoritative GAAP, except for rules and interpretive releases of the Securities and Exchange Commission (SEC), which are sources of authoritative GAAP for SEC registrants. The adoption of the ASC was not intended to change or alter existing GAAP and therefore did not have any impact on the Authority's consolidated financial statements. References to the relevant ASC section and the previously existing GAAP standard have been provided for accounting standards adopted in 2009 but prior to the effective date of the ASC.

Recent Accounting Pronouncements

In June 2008, the GASB issued Statement No. 51, *Accounting and Financial Reporting for Intangible Assets*. This statement provides guidance regarding how to identify, account for, and report intangible assets. GASB Statement No. 51 is effective for financial statements for periods beginning after June 15, 2009. The adoption of this statement is not expected to have a material impact on the Authority's financial position or net assets.

Also in June 2008, GASB issued Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments*. This statement requires that the fair value of financial arrangements called "derivatives" or "derivative instruments" be reported in the financial statements of state and local governments. If a derivative effectively hedges (significantly reduces) an identified risk of rising or falling cash flows or fair values, then its annual fair value changes are deferred until the hedged transaction occurs or the derivative ceases to be effective. On the other hand, the annual change in the fair value of *other* derivatives should be reported immediately as investment income or loss. Additional information about derivatives should be disclosed in the notes to the financial statements, including identification of the risks to which hedging derivative instruments expose the Authority. GASB No. 53 is effective for financial statements for periods beginning after June 15, 2009. The Authority is currently assessing the financial statement impact of adopting this statement, but does not believe that its impact will be material.

(4) Fair Value of Financial Instruments

The Authority records its financial instruments related to continuing operations at fair value as shown below (amounts in thousands):

		Carrying amount/fair value Year ended December 31,	
		2009	2008
Investments	$	124,283	32,562
Nuclear Decommissioning Trust (included in nonutility plant and other investments)		74,548	71,623
Derivative liabilities:			
Financial derivatives (Interest rate swaps)		(231,576)	(497,674)
Fuel and purchased power derivatives		(179,539)	(357,131)

The fair values of the financial instruments shown in the above table represent management's best estimates of the amounts that would be received to sell those assets or that would be paid to transfer those liabilities in an orderly transaction between market participants at that date. Those fair value measurements maximize the use of observable inputs. However, in situations where there is little, if any, market activity for the asset or liability at the measurement date, the fair value measurement reflects the Authority's own judgments about the assumptions that market participants would use in pricing the asset or liability. Those judgments are developed by the Authority, in consultation with its risk management advisors, based on the best information available in the circumstances.

The Authority obtained the estimated fair market value of long-term debt from its financial advisor. The financial advisor developed estimated market scales and prices for each type of debt security by taking into account credit ratings, bond insurance, call provisions and any other unique features.

(a) Adoption of FASB ASC 820 Fair Value Measurements and Disclosures

The Authority adopted FASB ASC 820, *Fair Value Measurements and Disclosures* on January 1, 2008, for applicable financial instruments that are measured at fair value. This statement establishes a framework for measuring fair value, and expands disclosures about fair value measurements.

FASB ASC 820 *Fair Value Measurements and Disclosures* establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities that the Authority has the ability to access as of the measurement date. The financial instruments utilizing Level 1 inputs include active exchange-traded securities, exchange based derivatives, and investments in U.S. Treasuries.
- Level 2 – Inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. The financial instruments utilizing Level 2 inputs include fixed income securities, exchange-based derivatives, and over-the-counter derivatives such as swaps, options and forwards.
- Level 3 – Unobservable inputs for the asset or liability only used when there is little, if any, market activity for the asset or liability at the measurement date. The financial instruments utilizing Level 3 inputs include infrequently traded, and nonexchange-based derivatives and commingled investment funds, and are measured using present value pricing models.

In accordance with FASB ASC 820 *Fair Value Measurements and Disclosures*, the Authority determines each items level in the fair value hierarchy in its entirety based on the lowest level input that is significant to its fair value measurement.

(b) Recurring Fair Value Measurements

The following table presents assets and liabilities measured and recorded at fair value on the Authority’s balance sheet on a recurring basis and their level within the fair value hierarchy as of December 31, 2009 (amounts in thousands):

		Fair value December 31, 2009			
		Level 1	**Level 2**	**Level 3**	**Total**
Investments	$	—	124,283	—	124,283
Nuclear Decommissioning Trust investments		25,247	37,673	11,628	74,548
Derivative liabilities:					
Financial derivatives		—	—	(231,576)	(231,576)
Fuel and purchased power derivatives		(163,017)	—	(16,522)	(179,539)
Total	$	(137,770)	161,956	(236,470)	(212,284)

The following table reconciles, for the period ended December 31, 2009, the beginning and ending balances for financial instruments that are recognized at fair value in the financial statements at least annually using significant unobservable inputs (amounts in thousands):

	Fair value measurement using significant unobservable inputs (Level 3)			
	NDT fund investments	Financial derivatives	Fuel and purchased power derivatives	Total
Beginning balance at January 1, 2009	$ 8,947	(497,674)	(72,992)	(561,719)
Total realized/unrealized gains and (losses) Included in net assets (realized)	1,787	5,606	38,383	45,776
Included in decommissioning obligations/unrealized gains	579	—	—	579
Included in regulatory asset/deferred unrealized loss	—	260,492	18,049	278,541
Purchase (sales), net	315	—	(7,035)	(6,720)
Transfer into Level 3	—	—	7,073	7,073
Ending balance at December 31, 2009	$ 11,628	(231,576)	(16,522)	(236,470)

Realized gains and losses included in net assets that are related to the financial derivatives are recorded as a component of interest expense, while those related to energy derivatives are recorded as fuel and purchased power expense.

Unrealized gains and losses related to derivatives are deferred until realized in accordance with how customer rates are set and determined.

(c) Nonderivative Fair Value Measurements

Debt securities are measured using quoted market prices multiplied by the quantity held when quoted market prices are available. If quoted market prices for those debt securities are not available, the fair value is determined using an income approach valuation technique (present value using the discount rate adjustment technique) that considers, among other things, interest rates, the issuer's credit spread, bond insurance, call provisions and illiquidity by sector and maturity. Commingled funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of commingled funds are based on net asset values per fund share (the unit of account), derived from the quoted prices in active markets of the underlying equity securities. However, because the shares in the commingled funds are not publicly quoted, not traded in an active market and are subject to certain restrictions regarding their purchase and sale, the commingled funds are categorized in Level 3.

(d) Derivative Fair Value Measurements

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 discount the fair value of each contract using a interest rate which represents default risk associated with a particular counterparty.

Under the guidance of FASB Staff Position (FSP) FIN 39-1, entities may choose to offset derivative positions in the financial statements against the fair value of the amounts recognized as cash collateral paid or received under those arrangements. The Authority has credit arrangements within various agreements to call on or pay additional collateral support. The Authority has chosen not to offset positions as defined in this FSP. As of December 31, 2009 and 2008, the Authority recorded approximately \$46 million and \$229 million, respectively, of cash collateral paid on its balance sheet.

(e) Other Derivative Disclosures

Interest Rate Transactions

The Authority has entered into several interest rate swap agreements with various counterparties to modify the effective interest rate on outstanding debt. The following tables show the notional amounts, fair values, and the net settlement amounts of derivative contracts (amounts in thousands):

Notional amount	Termination date	Type of swap		December 31, 2009 Fair value	December 31, 2009 Deferred unrealized loss
$ 150,000	4/1/2025	Floating to fixed		$ (16,065)	(16,065)
100,000	4/1/2025	Floating to fixed		(10,710)	(10,710)
587,225	12/1/2029	Floating to fixed	*(a)*	(162,492)	(82,526)
110,715	9/1/2015	Floating to fixed		(6,338)	(6,338)
502,090	8/15/2033	Basis swap	*(b)*	(17,985)	(5,135)
251,045	8/15/2033	Basis swap	*(c)*	(8,993)	(2,568)
251,045	8/15/2033	Basis swap	*(c)*	(8,993)	(2,568)
		Total		$ (231,576)	(125,910)

(a) The Authority received an upfront premium totaling approximately $106 million, of which $24.4 million represented reimbursement of administrative costs.

(b) The Authority received an upfront premium totaling approximately $17.5 million.

(c) The Authority received an upfront premium totaling approximately $8.75 million per swap.

The interest rate transactions are all cash flow hedges. Unrealized gains and losses resulting from changes in the mark-to-market valuations are deferred until realized, at which point settlements will become components of interest expense and subject to recovery from our customers. The swaps terminate with the underlying debt unless reassigned to other debt (amounts in thousands).

Description hedge	Fair value at December 31, 2009	Net settlements receipts/ (payments) 2009	Fair value at December 31, 2008	Net settlements receipts/ (payments) 2008
Basis swaps	$ (35,971)	(1,968)	(120,367)	(2,314)
Floating to fixed swaps	(195,605)	(37,605)	(377,307)	(21,490)
Total interest rate items	$ (231,576)	(39,573)	(497,674)	(23,804)

Energy Related Transactions

Notional Volume of Energy Related Transactions

	Long swap	Short swap	Long call	Short put
Commodity (volume):				
Oil (bbls)	5,403,655	2,478,500	770,000	770,000
NG (MMBtu)	70,690,000	14,547,500	13,345,000	13,345,000
NG Basis (MMBtu)	5,322,500	—	—	—
Power (MWh)	4,333,600	4,333,600	—	—

(Amounts in thousands)

	Fair value at December 31, 2009	Net settlements receipts/ (payments) 2009	Fair value at December 31, 2008	Net settlements receipts/ (payments) 2008
Oil (bbls):				
Unrealized fair value gains	$ 49,668		133,057	
Unrealized fair value losses	(32,181)		(163,521)	
Net oil	17,487	$ 73,011	(30,464)	113,143
Natural gas (MMBtu):				
Unrealized fair value gains	3,279		11,421	
Unrealized fair value losses	(133,568)		(136,400)	
Net natural gas	(130,289)	(35,534)	(124,979)	61,128
Natural gas basis (MMBtu):				
Unrealized fair value gains	—		—	
Unrealized fair value losses	(3,774)		(9,430)	
Net natural gas basis	(3,774)	(10,455)	(9,430)	1,743
Power (MWh):				
Unrealized fair value gains	3,048		4,729	
Unrealized fair value losses	(66,010)		(196,988)	
Net power	(62,962)	(133,857)	(192,259)	40,047
Total energy derivatives	$ (179,538)	(106,835)	(357,132)	216,061

(Continued)

The energy related transactions are all cash flow hedges. Unrealized gains and losses are deferred until realized, at which point they become a component of fuel and purchased power, either increasing or decreasing that cost, and subject to recovery under the FPPCA.

(5) Rate Matters

Under current New York State law, 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, the Authority has agreed, 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), that it will 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. Another of the PACB conditions requires that the Authority reduce average base rates within the service area by no less than 14% over a ten-year period commencing on the date when the Authority began providing electric service, when measured against LILCO's base rates in effect on July 16, 1997 (excluding the impact of the Shoreham Property Tax Settlement, but adjusted to reflect emergency conditions and extraordinary unforeseeable events, including a precipitous rise in oil prices).

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, and to establish or maintain any reserves or other funds or accounts required or established by or pursuant to the terms of such resolution.

The Authority's tariff 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 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 renewables program; and (v) a rider providing for the collection of the Temporary State Assessment imposed by the New York State Legislature.

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, 2009 (amounts in thousands):

	Beginning balance	Additions	Deletions	Ending balance
Capital assets, not being depreciated:				
Land	$ 16,089	604	—	16,693
Retirement work in progress	34,159	19,480	17,699	35,940
Construction in progress	272,733	243,370	327,005	189,098
Total capital assets not being depreciated	322,981	263,454	344,704	241,731
Capital assets, being depreciated:				
Generation – nuclear	713,876	7,341	13,139	708,078
Transmission and distribution	3,047,676	307,161	70,786	3,284,051
Common	31,493	6,435	734	37,194
Nuclear fuel in process and in reactor	73,207	20,584	—	93,791
Office equipment, furniture, and leasehold improvements	4,607	673	—	5,280
Generation and transmission assets under capital lease	2,818,947	736,077	—	3,555,024
Total capital assets being depreciated	6,689,806	1,078,271	84,659	7,683,418
Less accumulated depreciation for:				
Generation – nuclear	233,524	21,862	4,460	250,926
Transmission and distribution	634,898	115,664	76,406	674,156
Common	8,767	4,392	475	12,684
Nuclear fuel in process and in reactor	60,083	6,690	—	66,773
Office equipment, furniture, and leasehold improvements	3,570	377	—	3,947
Generation assets under capital lease	346,935	110,010	—	456,945
Total accumulated depreciation	1,287,777	258,995	81,341	1,465,431
Net value of capital assets, being depreciated	5,402,029	819,276	3,318	6,217,987
Net value of all capital assets	$ 5,725,010	1,082,730	348,022	6,459,718

In 2009, depreciation expense related to capital assets was approximately $142 million.

The following schedule summarizes the utility plant and property and equipment of the Authority as of December 31, 2008 (amounts in thousands):

		Beginning balance	Additions	Deletions	Ending balance
Capital assets, not being depreciated:					
Land	$	15,712	377	—	16,089
Retirement work in progress		24,809	18,930	9,580	34,159
Construction in progress		208,342	283,568	219,177	272,733
Total capital assets not being depreciated		248,863	302,875	228,757	322,981
Capital assets, being depreciated:					
Generation – nuclear		711,256	2,620	—	713,876
Transmission and distribution		2,866,566	205,547	24,437	3,047,676
Common		26,093	5,786	386	31,493
Nuclear fuel in process and in reactor		72,758	578	129	73,207
Office equipment, furniture, and leasehold improvements		3,966	641	—	4,607
Generation and transmission assets under capital lease		2,474,902	344,045	—	2,818,947
Total capital assets being depreciated		6,155,541	559,217	24,952	6,689,806
Less accumulated depreciation for:					
Generation – nuclear		211,247	22,277	—	233,524
Transmission and distribution		554,560	110,829	30,491	634,898
Common		6,547	2,606	386	8,767
Nuclear fuel in process and in reactor		54,177	5,906	—	60,083
Office equipment, furniture, and leasehold improvements		3,228	342	—	3,570
Generation assets under capital lease		253,905	93,030	—	346,935
Total accumulated depreciation		1,083,664	234,990	30,877	1,287,777
Net value of capital assets, being depreciated		5,071,877	324,227	(5,925)	5,402,029
Net value of all capital assets	$	5,320,740	627,102	222,832	5,725,010

(Continued)

In 2008, depreciation expense related to capital assets was approximately $134 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 in Scriba, 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 net utility plant investment, excluding nuclear fuel, was approximately $457 million and $480 million as of December 31, 2009 and 2008, 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 a site-specific study prepared by Constellation. As a result of that study, the Authority's share of the total decommissioning costs for both the contaminated and noncontaminated portions decreased approximately $20 million (due to improved remediation technologies) to $68 million as of December 31, 2009 and is included in the balance sheet as a component of the asset retirement obligation. The Authority maintains a nuclear decommissioning trust fund (NDT) for its share of the decommissioning costs of NMP2, which as of December 31, 2009 and 2008, had an approximate value of $75 million and $72 million, respectively. Through continued deposits and investment returns being maintained within these trusts, the Authority believes that the value of these trusts in 2046 will be sufficient to meet the Authority's expected decommissioning obligations.

(b) NMP2 Radioactive Waste

Constellation has contracted with the U.S. Department of Energy (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 forecasted the start of operations of its high-level radioactive waste repository to be no earlier than 2010. The Authority has been advised by Constellation that the NMP2 spent fuel storage pool has a capacity for spent fuel that is adequate until 2012. If additional DOE schedule slippage should occur, the storage for NMP2 spent fuel, either at the plant or some alternative location, may be required. 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 signed into law in 2002, which was then 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 international 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.

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 insurer's 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 $300 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 and $300 million for occurrences of radiation injury claims against all those insured by this policy on or after January 1, 2003.

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 exceed accumulated reserves. 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.

(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. 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 (AAA), repurchase agreements (A-1), bankers' acceptances (AA- or Aa3), 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), mutual funds (AAAm or AAAm-G), investment contracts (AA- or Aa3), municipal obligations (AA- or Aa3), and variable rate notes (no credit rating limit). The Authority's investment policy prohibits investments involving complex derivatives, reverse repurchase agreements, 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 35%, (iii) repurchase agreements up to 10% or $50 million, (iv) mutual funds up to 50% 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 Chief Financial Officer.

As of December 31, 2009 and 2008, the Authority had deposits of $12 million, of which approximately $6 million and $8 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 is held in an account for the Authority and ranges from 102% to 105% of the deposit balances.

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. The duration of the Authority's investment maturities are detailed in the chart below.

As of December 31, 2009 and 2008, the Authority had the following investments and maturities (amounts in thousands):

					2009	
					Investment maturities	
Deposit/investment type		**2009 Fair value**	**Percent of portfolio**		**Less than 3 months**	**3 months to 1 year**
Short-term discount notes:						
Commercial paper	$	257,856	52%	$	142,572	115,284
Federal agencies		9,399	2		400	8,999
Master notes/money markets		214,793	43		214,793	—
Cash and collateralized deposits		13,499	3		13,499	—
Total	$	495,547	100%	$	371,264	124,283

					2008	
					Investment maturities	
Deposit/investment type		**2008 Fair value**	**Percent of portfolio**		**Less than 3 months**	**3 months to 1 year**
Short-term discount notes:						
Commercial paper	$	132,136	52%	$	107,916	24,220
Federal agencies		4,992	2		—	4,992
Master notes/money markets		105,684	42		105,684	—
Corporate indentures		3,350	1		—	3,350
Cash and collateralized deposits		11,558	3		11,558	—
Total	$	257,720	100%	$	225,158	32,562

(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 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, 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. In 2004 the Board of Trustees authorized the use of equity investments as a permissible vehicle within this portfolio and limited the maximum exposure to 35%. The NDT investment portfolio must be rebalanced quarterly at plus or minus 5% for equity investments. The fixed income 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, 2009 and 2008, LIPA had the following investments (amounts in thousands):

Investment type		2009 Fair value	Percent of portfolio
Corporate notes and bonds	$	21,346	29%
Mortgage obligations		1,629	2
U.S. government and its agencies obligations		39,960	54
Money market		300	—
Commingled equity fund		11,313	15
Total	$	74,548	100%

Investment type		2008 Fair value	Percent of portfolio
Corporate notes and bonds	$	16,452	23%
Mortgage obligations		1,846	3
U.S. government and its agencies obligations		43,729	61
Municipal securities		89	—
Money market		560	1
Commingled equity fund		8,947	12
Total	$	71,623	100%

The overall duration of the three individual accounts averaged 5.4 and 5.8 years at December 31, 2009 and 2008, 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, 2009 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	$ 367,921	7,078 (a)	86,610	—	288,389	77,620
Series 1998B	154,485	—	72,360	—	82,125	78,380
Series 2000A	387,302	22,478 (a)	—	—	409,780	30,825
Series 2001A	165,175	—	—	—	165,175	—
Series 2001B-K	75,000	—	—	75,000	—	—
Series 2003A	19,895	—	19,895	—	—	—
Series 2003B	271,355	—	8,845	—	262,510	12,245
Series 2003C	256,000	—	—	—	256,000	—
Series 2003D-O	587,225	—	—	—	587,225	—
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	327,565	—	640	—	326,925	665
Series 2006E	507,600	—	—	—	507,600	—
Series 2006F	514,495	—	—	—	514,495	—
Series 2008A	605,055	—	—	—	605,055	—
Series 2008B	149,340	—	—	—	149,340	—
Series 2009A	—	435,825	—	—	435,825	—
Subtotal	5,722,633	465,381	188,350	75,000	5,924,664	199,735
Electric system subordinate revenue bonds:						
Series 1-3	525,000	—	—	—	525,000	—
Series 7	156,100	—	—	156,100	—	—
Series 8	104,725	—	53,020	—	51,705	25,225
Subtotal	785,825	—	53,020	156,100	576,705	25,225
LIPA debt:						
NYSERDA notes	155,420	—	—	—	155,420	—
Net unamortized discounts/ premiums and deferred amortization	(28,144)	(2,786)	—	(6,537)	(24,393)	—
Total bonds and notes, net of unamortized discounts/premiums	$ 6,635,734	462,595	241,370	224,563	6,632,396	224,960
Other long-term liabilities:						
Deferred credits	$ 299,072	21,955	117,390	—	203,637	—
Claims and damages	28,030	50,683	39,847	—	38,866	—
Capital lease obligation	2,472,012	736,077	110,010	—	3,098,079	127,953
Total other long-term liabilities	$ 2,799,114	808,715	267,247	—	3,340,582	127,953

(a) Represents accretion of capital appreciation bonds

The Authority's bond and note indebtedness and other long-term liabilities as of December 31, 2008 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	$ 443,552	7,324 (a)	82,955	—	367,921	86,610
Series 1998B	271,210	—	116,725	—	154,485	72,360
Series 2000A	366,057	21,245 (a)	—	—	387,302	—
Series 2001A	165,175	—	—	—	165,175	—
Series 2001B-K	500,000	—	—	425,000	75,000	—
Series 2001L-P	200,000	—	—	200,000	—	—
Series 2003A	37,675	—	17,780	—	19,895	19,895
Series 2003B	279,850	—	8,495	—	271,355	8,845
Series 2003C	256,000	—	—	—	256,000	—
Series 2003D-O	587,225	—	—	—	587,225	—
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	328,180	—	615	—	327,565	640
Series 2006E	507,600	—	—	—	507,600	—
Series 2006F	514,495	—	—	—	514,495	—
Series 2008A	—	605,055	—	—	605,055	—
Series 2008B	—	149,340	—	—	149,340	—
Subtotal	5,791,239	782,964	226,570	625,000	5,722,633	188,350
Electric system subordinate revenue bonds:						
Series 1-3	525,000	—	—	—	525,000	—
Series 7	250,000	—	—	93,900	156,100	—
Series 8	104,725	—	—	—	104,725	53,020
Subtotal	879,725	—	—	93,900	785,825	53,020
LIPA debt:						
NYSERDA notes	155,420	—	—	—	155,420	—
Net unamortized discounts/ premiums and deferred amortization	2,899	(26,478)	—	4,565	(28,144)	—
Total bonds and notes, net of unamortized discounts/premiums	$ 6,829,283	756,486	226,570	723,465	6,635,734	241,370
Other long-term liabilities:						
Deferred credits	$ 331,075	16,351	48,354	—	299,072	—
Claims and damages	39,253	37,582	48,805	—	28,030	—
Capital lease obligation	2,220,997	344,045	93,030	—	2,472,012	102,844
Total other long-term liabilities	$ 2,591,325	397,978	190,189	—	2,799,114	102,844

(a) Represents accretion of capital appreciation bonds

The Authority's schedule of capitalization for the years ended December 31, 2009 and 2008 is as follows (amounts in thousands):

	Maturity	Interest rate		Series		December 31 2009	December 31 2008
Electric system general revenue bonds:							
Serial bonds	Annually to 2011	4.750% to 5.500%	a	1998 A	$	159,420	233,060
Capital appreciation bonds	December 1, 2012 to 2028	5.100% to 5.300%	a	1998 A		128,968	134,861
Serial bonds	Annually to 2011	4.400% to 5.250%	a	1998 B		82,125	154,485
Capital appreciation bonds	June 1, 2010 to 2029	5.360% to 5.950%	a	2000 A		409,781	387,302
Serial bonds	September 1, 2013 to 2014	4.600% to 4.700%	a, d	2001 A		745	745
Term bonds	September 1, 2027 to 2029	5.000% to 5.125%	a, d	2001 A		164,430	164,430
Term bonds	May 1, 2033	3.550%	b	2001 B		—	75,000
Serial bonds	June 1, 2009	5.000%	a	2003 A		—	19,895
Serial bonds	December 1, 2010 to 2014	4.00% to 5.25%	a, d	2003 B		262,510	271,355
Serial bonds	September 1, 2013 to 2028	4.25% to 5.00%	a, d	2003 C		70,480	70,480
Term bonds	September 1, 2027 to 2033	5.00% to 5.25%	a, d	2003 C		185,520	185,520
Term bonds	December 1, 2029	0.25% to 0.28%	c, d	2003 D-H		293,625	293,625
Term bonds	December 1, 2029	0.25% to 0.43%	c, d	2003 I-O		293,600	293,600
Serial bonds	September 1, 2013 to 2025	3.80% to 4.875%	a, d	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, d	2006A		839,245	839,245
Serial bonds	December 1, 2035	4.500%	a	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, 2010 to 2025	4.00% to 5.00%	a, d	2006D		326,925	327,565
Serial bonds	December 1, 2017 to 2022	4.00% to 5.00%	a, d	2006E		507,600	507,600
Serial bonds	May 1, 2011 to 2028	4.00% to 5.00%	a	2006F		401,915	401,915
Term bonds	May 1, 2030 to 2033	4.250%	a	2006F		112,580	112,580
Term bonds	May 1, 2031 to 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 5.75%	a	2009A		435,825	—
Electric system subordinated:							
Revenue bonds	May 1, 2033	0.70% to 0.80%	c, d	Series 1A-3A		275,000	275,000
	May 1, 2033	1.00% to 1.10%	c, d	Series 1B-3B		250,000	250,000
	April 1, 2025	4.210%	a, d	Series 7		—	156,100
	April 1, 2010 to 2011	4.00% to 5.00%	a	Series 8		51,705	104,725
Total general and subordinated revenue bonds						6,501,369	6,508,458
Commercial paper notes		0.35% to 0.50%	c	CP-1		100,000	100,000
		0.24% to 0.32%	c	CP-3		100,000	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 and deferred amortization						(24,393)	(28,144)
Total long-term debt						6,832,396	6,835,734
Less current maturities and short-term debt						424,960	441,370
Long-term debt						6,407,436	6,394,364
Net assets						329,704	289,178
Total capitalization					$	6,737,140	6,683,542

a Fixed rate.
b Variable rate (rate presented is as of December 31, 2008; amounts were redeemed during 2009);
c Variable rate (rate presented is as of December 31, 2009).
d Certain bonds of this series are subject to interest rate exchange agreements – please see note 4.

The debt service requirements for the Authority's bonds (excluding commercial paper notes) as of December 31, 2009 are as follows (amounts in thousands):

Due		Principal	Interest	Net swap payments	Total
2010	$	224,960	269,711	28,028	522,699
2011		238,100	269,814	20,353	528,267
2012		278,025	274,981	8,143	561,149
2013		176,060	266,181	7,097	449,338
2014		184,055	260,455	7,097	451,607
2015 – 2019		1,149,340	1,205,484	14,963	2,369,787
2020 – 2024		1,256,635	979,515	16,345	2,252,495
2025 – 2029		1,535,055	706,883	14,653	2,256,591
2030 – 2034		1,712,215	293,268	—	2,005,483
2035 – 2039		289,185	40,886	—	330,071
		7,043,630	4,567,178	116,679	11,727,487
Unamortized discounts/premiums		(24,393)	—	—	(24,393)
Unaccreted interest on capital appreciation bonds		(386,841)	—	—	(386,841)
Total	$	6,632,396	4,567,178	116,679	11,316,253

Future debt service on the variable rate bonds and floating rate portion of any floating-to-fixed rate swaps use an assumed rate of 1.50% for 2010; 2.50% for 2011; 4.00% for 2012 through 2014; and 4.50% 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

2009

In January 2009 the Authority issued $436 million of its Electric System General Revenue Bonds, Series 2009A. The proceeds of these fixed rate bonds including the premium of $9 million were used to redeem approximately $231 million of outstanding insured variable rate securities in a current refunding and to pay bond issuance costs totaling $3 million. The remaining proceeds were used to finance the on-going capital program. The refunding produced an approximate $45 million net present value savings. The 2009A bonds have an average life of 20 years and an all-in cost of 5.50%.

2008

In March 2008, the Authority redeemed $200 million of its insured variable rate Electric System General Revenue Bonds to lower the risks associated with their marketability. The Authority used cash on hand to redeem these securities. The Authority had deferred charges totaling approximately $4 million associated with these bonds that were recognized as an extraordinary loss on early extinguishment of debt.

In May 2008, the Authority, in response to the market-wide disruption in the Auction Rate Securities market, converted $293.6 million of its Electric System General Revenue Bonds Series I through O from Auction Rate mode to weekly variable rate demand notes.

In October 2008, the Authority issued approximately $605 million Electric System General Revenue Bonds, Series 2008A. The proceeds of these fixed rate bonds, net of discount and cost of issuance, were used to replenish the treasury for funds used to finance the Authority's on-going capital program and the remainder was used to redeem $375 million of the Authority's insured auction rate securities in November 2008. This current refunding produced an approximate $58 million net present value savings. The 2008A bonds have an average life of 23 years and an all-in cost of 6.23%.

In November 2008, the Authority issued approximately $149 million Electric System General Revenue Bonds, Series 2008B. The proceeds of these fixed rate bonds, net of discount and cost of issuance were used to redeem $144 million of insured variable rate securities. This current refunding produced an approximate $12 million net present value savings. The 2008B bonds have an average life of 17 years and an all-in cost of 5.99%.

(b) 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. In connection with the issuance of the Notes, the Authority has entered into a Letter of Credit and Reimbursement Agreement which was renegotiated in 2006. Under the terms of the renegotiated Letter of Credit and Reimbursement Agreement, $250 million expires June 15, 2011 and the remaining $50 million expires on December 15, 2015, subject to the right of early termination by the bank on June 15, 2012. 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.

The Authority's short-term indebtedness as of December 31, 2009 and 2008 is comprised of the following obligations (amounts in thousands):

	2009			
	Beginning balance	Issuances	Retirements	Ending balance
Short-term debt – CP-1	$ 100,000	230,600	(230,600)	100,000
Short-term debt – CP-3	100,000	617,000	(617,000)	100,000
	$ 200,000	847,600	(847,600)	200,000

		2008			
		Beginning balance	**Issuances**	**Retirements**	**Ending balance**
Short-term debt – CP-1	$	100,000	402,600	(402,600)	100,000
Short-term debt – CP-3		—	100,000	—	100,000
	$	100,000	502,600	(402,600)	200,000

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

The fair values of the Authority's long-term debt as of December 31, 2009 and 2008 were as follows (amounts in thousands):

		Fair value December 31,	
		2009	**2008**
Electric System General Revenue Bonds, Series 1998 A	$	313,580	378,622
Electric System General Revenue Bonds, Series 1998 B		83,002	156,159
Electric System General Revenue Bonds, Series 2000 A		475,915	404,217
Electric System General Revenue Bonds, Series 2001 A		166,488	149,162
Electric System General Revenue Bonds, Series 2001 B		—	75,000
Electric System General Revenue Bonds, Series 2003 A		—	20,208
Electric System General Revenue Bonds, Series 2003 B		290,276	290,051
Electric System General Revenue Bonds, Series 2003 C		262,348	230,181
Electric System General Revenue Bonds, Series 2003 D-O		587,225	587,225
Electric System General Revenue Bonds, Series 2004 A		202,288	176,331
Electric System General Revenue Bonds, Series 2006 A		871,972	789,764
Electric System General Revenue Bonds, Series 2006 B		95,674	81,869
Electric System General Revenue Bonds, Series 2006 C		196,262	167,895
Electric System General Revenue Bonds, Series 2006 D		336,568	314,650
Electric System General Revenue Bonds, Series 2006 E		537,783	499,926
Electric System General Revenue Bonds, Series 2006 F		530,211	494,983
Electric System General Revenue Bonds, Series 2008 A		649,220	593,448
Electric System General Revenue Bonds, Series 2008 B		162,409	147,822
Electric System General Revenue Bonds, Series 2009 A		468,094	—
Electric System Subordinated Revenue Bonds, Series 1-3 and 1-6		525,000	525,000
Electric System Subordinated Revenue Bonds, Series 7		—	156,100
Electric System Subordinated Revenue Bonds, Series 8A		—	26,124
Electric System Subordinated Revenue Bonds, Series 8B		—	27,405
Electric System Subordinated Revenue Bonds, Series 8C		25,487	26,086
Electric System Subordinated Revenue Bonds, Series 8F		27,595	27,388
NYSERDA Notes		156,368	152,623
Total	$	6,963,765	6,498,239

(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 July 17, 1998; all benefits generally vest after five years of accredited service.

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. Effective October 1, 2000, members of the System with at least 10 years of service or membership no longer contribute 3% of their gross salaries. The Authority pays the entire amount of the annual contributions of these employees.

Under this plan, the Authority's required contributions and payments made to the System were approximately $572,000, $713,000, and $892,000, for the years ended December 31, 2009, 2008, and 2007, 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% the cost of dependent coverage for health insurance benefits. Participants include 96 current employees and retired and/or spouses of retired employees who were eligible to receive these benefits at December 31, 2009. 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.

Effective January 1, 2007, the Authority prospectively implemented accrual accounting for its OPEB obligations, based on the approach provided in GASB Statement No. 45, *Accounting and Financial Reporting for Post Employment Benefits Other Than Pensions*, issued in June 2004. Prior to adoption, OPEB provisions were recorded on a pay-as-you-go basis. The first actuarial valuation date was January 1, 2007, and the Authority had not previously recognized an OPEB liability. Actuarial valuations involve estimates of the value of reported amounts and assumptions about the probability of events in the future. Examples include assumptions about employment mortality and the healthcare cost trend. Amounts determined regarding the annual required contributions of the employer are subject to continual revision as actual results are compared to past expectations and new estimates are made about the future.

The Authority's annual OPEB cost for the plan is calculated based on the Annual Required Contribution (ARC), an amount actuarially determined in accordance with the parameters of GASB Statement No. 45. GASB 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 $15.7 million at December 31, 2009), and as the Authority has not actually funded the "required" amount, future valuations may produce larger ARCs. The current period ARC is approximately $2.1 million as detailed in the chart.

(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 continues to be 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 2009 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, 2009 and 2008 is as follows (amounts in thousands):

		2009	2008
Annual OPEB cost:			
Annual required contribution (ARC):			
Normal cost	$	1,412	1,219
Amortization payment		13,854	12,050
Interest to the end of the year		570	597
Total		15,836	13,866
ARC adjustment		(14,245)	(12,604)
Interest on net OPEB obligation		515	543
Annual OPEB cost	$	2,106	1,805
Net OPEB obligation:			
Net OPEB obligation at beginning of fiscal year	$	13,731	12,061
Annual required contribution:			
Annual OPEB cost		2,106	1,805
Employer contribution:			
Payments for retirees during the year		123	135
To a trust		—	—
Net OPEB obligation at end of fiscal year	$	15,714	13,731

Actuarial valuation date		December 31, 2009	July 1, 2007
Actuarial value of assets	$	—	—
Accrued actuarial liability (AAL)		16,680	11,224
Unfunded AAL		16,680	11,224
Funded ratio		—%	—%
Covered payroll	$	10,980	9,859
UAAL as % covered payroll		151.9%	113.8%

(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-fire 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 newly negotiated terms for a period of up to 15 years. The rates are adjusted annually in accordance with the formula established in the PSA. The annual capacity charge in 2009 and 2008 was approximately $422 million and $363 million, respectively, and the variable charge remained unchanged 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 averaged approximately $3 million in 2009 and approximately $4 million 2008.

(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 energy produced at the NYPA facility located within the service territory at Holtsville, New York. The Authority is required to reimburse NYPA for the minimum debt service payments and to make fixed nonenergy payments associated with operating and maintaining the plant.

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 will 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:				
2010	$ 33,046	20,780	75,200	129,026
2011	33,371	20,860	76,400	130,631
2012	33,652	21,680	73,900	129,232
2013	33,912	21,120	60,300	115,332
2014	33,905	21,200	52,900	108,005
2015 through 2019	174,413	107,250	71,000	352,663
2020 through 2024	13,374	47,610	—	60,984
2025 through 2029	—	23,260	—	23,260
2030 through 2034	—	24,700	—	24,700
Total	$ 355,673	308,460	409,700	1,073,833

* Assumes full performance by NYPA and the IPPs.

(c) Additional Power Purchase 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.

In accordance with the provisions of FASB ASC 840 *Leases* (previously FASB Emerging Issues Task Force Issue No. 01-08, *Determining Whether an Arrangements is a Lease* and SFAS No. 13, *Accounting for Leases*), all but one of the generating units, have been accounted for as capitalized lease obligations, whereas the one remaining unit, is accounted for as operating leases.

During 2009, the Authority began to acquire 286 MW from a 326MW plant that was constructed on Long Island. The Authority also purchases up to 345 MW of capacity and varying amounts of energy from a portfolio of facilities located in New England. This power is transmitted to Long Island via an undersea high voltage cable running between Connecticut and Long Island pursuant to a long-term firm transmission capacity purchase agreement.

Furthermore, in 2007, the Authority began purchasing 660 MW of transmission capacity via an undersea high voltage cable between New Jersey and New York. The Authority has also entered into an agreement with the owners of a facility located in PJM-ISO for a long-term capacity purchase that will commence on June 1, 2010.

The Authority has also entered into two contracts for the purchase of renewable energy from off-Island sources starting in 2009 and two additional contracts for power to be produced by solar photovoltaic power plants to be constructed in 2010 and 2011 at various sites on Long Island.

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

		Capitalized leases	Other
Minimum lease/rental payments:			
2010	$	293,253	1,819
2011		293,896	1,824
2012		295,282	1,830
2013		296,321	1,836
2014		297,852	1,842
2015 through 2019		1,398,670	9,309
2020 through 2024		1,152,219	9,482
2025 through 2029		677,902	9,674
2030 through 2034		66,667	8,554
Total		4,772,062	46,170
Less imputed interest		1,673,983	—
Net present value	$	3,098,079	46,170

(d) Office Lease

The Authority entered into an office lease agreement through January 31, 2011. The future minimum payments under the lease are as follows (amounts in thousands):

Year ended December 31:		
2010	$	1,550
2011		129
Total	$	1,679

Rental expense for the office lease amounted to approximately $1.7 million and $1.6 million for the years ended December 31, 2009 and 2008, respectively.

(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 for property damage to its transmission and distribution system and up to $3 million for general liability, including automobile liability. The Authority purchased commercially available excess general liability insurance for claims above the $3 million self insurance provision.

(13) Legal Proceedings

(a) Authority to Set 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 PSC or any other State regulatory body. However, the Authority agreed, in connection with the approval of the LIPA/LILCO Merger by the 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 unanimously passed by the New York State Legislature in June 2008, which would 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 become law, the Authority would have 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 require 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. On March 10, 2010, the Assembly passed the bill. However, to date, the Senate has not taken any further action. The Authority cannot predict whether this bill will become law or whether other similar legislation may 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 (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.

Metal Bank – In December 1997, the EPA issued its Record of Decision (ROD), in connection with the remediation of a licensed disposal site located in Philadelphia, Pennsylvania, and operated by Metal Bank of America. In the ROD, the EPA estimated that the cost of the selected remedy for the site to be $17.3 million. In June 1998, the EPA issued a Unilateral Administrative Order to 13 Potential Responsible Parties (PRPs), including the Authority, for the remedial design and for remedial action at the site. Under a PRP Participation Agreement, the Authority was responsible for 7.96% of the costs associated with implementing the remedy. The Authority has recorded a liability equal to its estimated cost representing its estimated share of the additional cost to remediate this site.

In 2005, Final Consent Decrees were published for public comment, the public hearing was held, and the Federal Judge approved the Decrees, making all the settlement terms final. The remedy was completed during the winter of 2009 – 2010.

PCB Treatment Inc. – LILCO has also been named a PRP for disposal sites in Kansas City, Kansas and Kansas City, Missouri. The two sites were used by a company named PCB Treatment, Inc. from 1982 until 1987 for the storage, processing, and treatment of electric equipment, oils, and other materials containing Polychlorinated Biphenyls (PCBs). According to the EPA, the buildings and certain soil areas outside the buildings were contaminated with PCBs. Certain of the PRPs, including

LILCO and several other utilities, formed a group, signed a Consent Order and investigated environmental conditions at these properties. Upon completion of the investigations, the PRPs, including the Authority, signed a second Consent Order that obligated them to clean up and restore the two contaminated properties. The Authority has been determined to be responsible for less than 1% of the materials that were shipped to this site. The remedial work has been completed and the site has been formally closed out by the EPA. The PRP Group distributed surplus funds to the Group members in December 2009.

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 25, 2010. 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 can 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 present demand from the Attorney General is $4.75 million. The JDG is in negotiations with the Attorney General to resolve this matter. LIPA's share of this is approximately $371,000.

(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 an additional 15,000 cubic yards of sand on various properties within the Village. The Authority and National Grid are currently negotiating with the Army Corps on this permit condition. 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 sulfur dioxide 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 when necessary. Generating units may be required to purchase additional allowances above the PSA unit allocations, or make other expenditures, based on changes in fuel prices or more restrictive regulations.

In 2003 the State of New York promulgated separate regulations that would further limit SO2 and NOx beginning in 2004. The PSA units have been complying with the NOx requirements without additional material expenditures, and lower sulfur fuel (0.7% S) has been used at Northport and Port Jefferson to meet the SO2 regulations. No additional reduction in fuel sulfur or allowance purchase is expected to be needed to comply with this regulation. In 2005, the State of New York adopted additional SO2 and NOx limits pursuant to its acid deposition program.

In March 2005, the Federal Clean Air Interstate Rule (CAIR) was promulgated, requiring further reduction 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, plans on installing additional NOx controls on all the units at Northport and Port Jefferson, to help further reduce NOx emissions. The CAIR rules will require the surrender of two SO2 allowances for each ton of SO2 emissions beginning in 2010 and 2.86 allowances per ton of emission in 2015 and beyond. Future projections indicate that the PSA units should be able to comply with the more restrictive surrender ratios by using their existing annual allowance allocations. Though not expected to be necessary, further SO2 reductions, if needed for CAIR compliance, could be achieved through the use of lower sulfur fuels (lower percent sulfur oil or natural gas) or the purchase and use of additional emission allowances. In response to a lawsuit filed by states, environmental groups and industry, on July 11, 2008, the United States Court of Appeals for the District of Columbia issued a decision finding fatal flaws with the CAIR rule, and thus vacated the rule in its entirety and remanded it back to EPA. That decision raised concerns about the price for NOx and SO2 allowances and the states' strategies for addressing their ozone and fine particulate matter State Implementation Plans. Pursuant to a petition for rehearing, on December 23, 2008, the D.C. Circuit modified its decision, remanding without vacatur EPA's CAIR rule. While the first phase for NOx compliance is now in effect as an interim measure before EPA reissues CAIR, consistent with the Court's decision, and it is possible that the new Administration will use this rulemaking effort to reduce the overall SO2 and NOx caps further.

The EPA has stated its intent to issue a proposed replacement rule in Spring 2010. The planned installation of Separated Over Fire Air on the four Northport and two Port Jefferson units, as well as a contemplated installation of water injection on additional Holtsville combustion turbines is expected to make significant reductions to NOx emissions that may be sufficient to comply with the new rules. Compliance with new SOx limits will likely be achieved with the existing SOx allowance bank, and fuel switching. However, additional controls or allowance purchases may be needed depending on the level of reductions ultimately required.

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 CAIR program will meet the requirements of the Regional Haze Rule, the DEC has proposed its own regulations, including the Best Available Retrofit Technology requirements. The rule, as proposed, requires eligible units (EF Barrett 2 and Northport 1-4) to conduct modeling to determine visibility impacts and to then determine what controls are necessary to reduce the impact. As with the CAIR rule, the installation of Separated Over Fire Air at Northport and E. F.Barrett Unit 2 may be sufficient to comply with the Regional Haze Rule. However, additional control may be needed depending on the level of reductions required. The proposed regulation will require the modeling to be conducted prior to October 2010.

Another rule issued in 2005, the Clean Air Mercury Rule (CAMR) had set new limits for mercury emissions from coal-fueled plants; it does not apply to the PSA units. The rulemaking process considered regulating nickel emissions from oil fired units which would have affected some PSA units and units under PPAs that burn oil, but ultimately did not. On February 8, 2008, the D.C. Circuit vacated the CAMR regulation and remanded the regulation back to EPA. Accordingly, it can not be determined how EPA will redevelop the regulation or what, if any, future compliance obligations will be imposed on generating units burning residual fuel oil. Any new regulations designed to reduce mercury emissions from coal plants could impact the pricing of purchased power.

As a result of the D.C. Circuit's vacating the CAMR Rule, EPA is required to determine at what level to regulate Hazardous Air Pollutants from oil and coal fired electric generating units and is requiring significant stack testing at two Northport units and one Port Jefferson unit (as well as at most oil fired units around the country) to be completed by September 2010. Testing will be performed on 100% oil. EPA will evaluate all the data received from all the testing to determine an emissions level. At this point, it is not possible to determine what, if any, additional controls may be required at Northport and Port Jefferson, or other units.

In 2005, seven Northeast states signed a Memorandum of Understanding called the Regional Greenhouse Gas Initiative (RGGI) for the purpose of capping and then reducing greenhouse gas emissions from power plants. At this time, ten Northeast states have signed on. After January 1, 2009, the ten states' rules required power plants to obtain enough carbon dioxide (CO2) allowances to cover their emissions over a three year compliance period. 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 from its customers in the year incurred as provided under the FPPCA. In 2009, these costs totaled approximately $16 million. Several initiatives, including a cap and trade program, carbon tax, and/or source specific control requirements, are also being considered at the federal level. It is unclear at this time what the scope and cost of a federal program might be.

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 VOCs 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 based on any 24 month period during the prior five year period. Depending on the baseline year adopted by regulations, which have not yet been proposed, some of the PSA units and units under the PPAs might be subject to this fee requirement.

The State of New York is also in the process of developing its eight hour ozone and fine particulate matter State Implementation Plans. While not yet proposed, the State intends to revise its existing regulations to require that sources of particulate matter sized 2.5 microns or smaller (PM2.5) with the potential to emit 100 tons per year will be required to perform case by case Reasonable Available Control Technology (RACT) analyses, and the State might also develop more stringent NOx RACT requirements. In addition, in 2007, member states of the Ozone Transport Commission determined that additional NOx emission reductions would be required from electric generating facilities during High Electric Demand Days (HEDD). NYSDEC has issued a proposed revision to 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 planned installation of Separated Over Fire Air 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 may be sufficient to comply with the new rules. However, additional control may be needed depending on the ultimate level of reductions required.

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 in most cases implementing technologies and procedures to reduce cooling water flow during certain periods should be sufficient to meet the performance standards established by the DEC.

DEC has issued draft SPDES permits for the Glenwood, Port Jefferson and E.F. Barrett power stations. With respect to Glenwood, the DEC agreed with National Grid that cooling towers are not required and will allow the plant to operate at its projected low capacity factor until 2013 at which time it would need to install other fish protection technologies if it were to operate beyond that date. For Port Jefferson, DEC also agreed that cooling towers would not be required but required additional fish protection technologies beyond those proposed by National Grid. In addition, two intervenors have requested that DEC impose cooling tower requirements at Glenwood and Port Jefferson. For E.F. Barrett, DEC proposed cooling towers. It is expected that DEC will issue draft permits for Northport and Far Rockaway in 2010 but National Grid cannot predict with certainty the requirements that the DEC intends to propose.

National Grid has objected to the DEC's proposed requirements at Port Jefferson, and plans to submit comments objecting to DEC's proposed requirements at E.F. Barrett and has requested adjudicatory hearings for all three draft permits.

The nature and extent of any expenditure cannot be fully determined until ongoing analysis of the impacts and mitigation options are completed by DEC. At this time, estimates for compliance upgrades proposed by National Grid covering a range of potential mitigation options could be between $60 and $90 million. While detailed cost estimates have not yet been prepared for DEC's proposed BTA requirements, if cooling towers are installed at E.F. Barrett preliminary estimates indicate that costs would be approximately $107 million. The potential cost for installing cooling towers at all power stations could be on the order of $400 million, with additional maintenance and fuel costs, which may be passed through to the Authority.

The DEC is also contemplating additional regulation of petroleum storage tanks and spill protection systems. Such regulations could require more frequent and comprehensive inspection of existing storage tank internals and improved spill containment systems. Until such regulations are proposed it cannot be determined what additional capital and or operating expenditures may be.

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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 basic financial statements of the Long Island Power Authority (Authority) as of and for the year ended December 31, 2009, and have issued our report thereon dated March 26, 2010. 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

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 an 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 first paragraph of this section and was not designed to identify all deficiencies in internal control over financial reporting that might be deficiencies, significant deficiencies, or material weaknesses. 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 basic 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 disclosed no instances of noncompliance or other matters that are required to be reported under *Government Auditing Standards*.

This report is intended solely for the information and use of Authority management, the Authority's Board of Trustees, the New York State Division of the Budget and the New York State Office of the State Comptroller and is not intended to be and should not be used by anyone other than those specified parties.

KPMG LLP

March 26, 2010