National Grid North America Inc. and Subsidiaries
Consolidated Financial Statements
For the years ended March 31, 2015 and 2014

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES

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Independent Auditor's Report

To the Board of Directors of
National Grid North America Inc.

We have audited the accompanying consolidated financial statements of National Grid North America Inc. (the "Company"), which comprise the consolidated balance sheets as of March 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, cash flows, capitalization, and changes in shareholder's equity for the years then ended.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

Our responsibility is to express an opinion on the consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

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

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of National Grid North America Inc. at March 31, 2015 and 2014, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

September 18, 2015

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NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(in millions of dollars)

	Years Ended March 31, 2015	2014
Operating revenues:		
Electric services	**$ 7,138**	$ 7,177
Gas distribution	**5,164**	5,355
Other	**29**	24
Total operating revenues	**12,331**	12,556
Operating expenses:		
Purchased electricity	**2,514**	2,503
Purchased gas	**2,179**	2,360
Operations and maintenance	**4,564**	4,541
Depreciation and amortization	**952**	896
Other taxes	**1,002**	1,063
Total operating expenses	**11,211**	11,363
Operating income	**1,120**	1,193
Other income and (deductions):		
Interest on long-term debt	**(420)**	(427)
Other interest, including affiliate interest	**(169)**	(144)
Income from equity investments	**41**	35
Other deductions, net	**(53)**	(19)
Total other deductions, net	**(601)**	(555)
Income before income taxes	**519**	638
Income tax expense	**188**	178
Income from continuing operations	**331**	460
Income from discontinued operations, net of taxes	**12**	133
Net income	**343**	593
Net loss attributable to non-controlling interest	**18**	20
Net income attributable to common shares	**$ 361**	$ 613

The accompanying notes are an integral part of these consolidated financial statements.

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions of dollars)

	Years Ended March 31,	
	2015	2014
Net income attributable to common shares	**$ 343**	$ 593
Other comprehensive income (loss), net of taxes:		
Unrealized gains on securities	**6**	4
Change in pension and other postretirement obligations	**(238)**	212
Unrealized gains on hedges	**6**	4
Total other comprehensive (loss) income	**(226)**	220
Comprehensive income	**$ 117**	$ 813
Less: comprehensive loss attributable to non-controlling interest	**18**	20
Comprehensive income attributable to common shares	**$ 135**	$ 833
Related tax (expense) benefit:		
Unrealized gains on securities	**$ (4)**	$ (3)
Change in pension and other postretirement obligations	**167**	(148)
Unrealized gains on hedges	**(3)**	(3)
Total tax benefit (expense)	**$ 160**	$ (154)

The accompanying notes are an integral part of these consolidated financial statements.

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions of dollars)

	Years Ended March 31,	
	2015	2014
Operating activities:		
Net income	**$ 343**	$ 593
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**952**	896
Regulatory amortizations	**120**	50
Provision for deferred income taxes	**206**	241
Bad debt expense	**218**	136
Loss (income) from equity investments, net of dividends received	**6**	(10)
Goodwill impairment	**22**	-
Allowance for equity funds used during construction	**(19)**	(27)
Amortization of debt discount and issuance costs	**9**	3
Net postretirement benefits expense	**166**	113
Net environmental remediation payments	**(103)**	(136)
Share based compensation	**15**	-
Changes in operating assets and liabilities:		
Accounts receivable and other receivable, net, and unbilled revenues	**72**	(719)
Accounts receivable from/payable to affiliates, net	**(8)**	38
Inventory	**(46)**	45
Regulatory assets and liabilities, net	**(4)**	45
Derivative contracts	**206**	15
Prepaid and accrued taxes	**(86)**	(118)
Accounts payable and other liabilities	**(60)**	(131)
Renewable energy certificate obligations, net	**52**	89
Other, net	**61**	38
Net cash provided by operating activities	**2,122**	1,161
Investing activities:		
Capital expenditures	**(2,440)**	(1,960)
Changes in restricted cash and special deposits	**(355)**	66
Cost of removal and other	**(191)**	(206)
Net cash used in investing activities	**(2,986)**	(2,100)
Financing activities:		
Payments on long-term debt	**(2,327)**	(1,604)
Proceeds from long-term debt	**2,546**	1,737
Payment of debt issuance costs	**(7)**	-
Commercial paper issued (paid)	**161**	(244)
Affiliated money pool borrowing and receivables/payables, net	**4**	-
Advance from affiliate	**(750)**	750
Equity infusion from Parent	**-**	1,000
Other	**-**	33
Net cash (used in) provided by financing activities	**(373)**	1,672
Net (decrease) increase in cash and cash equivalents	**(1,237)**	733
Net cashflow from discontinued operations - operating	**96**	(352)
Net cashflow from discontinued operations - investing	**-**	28
Cash and cash equivalents, beginning of year	**1,594**	1,185
Cash and cash equivalents, end of year	**$ 453**	$ 1,594
Supplemental disclosures:		
Interest paid	$ (493)	$ (596)
Income taxes refunded (paid)	29	(108)
Significant non-cash items:		
Capital-related accruals included in accounts payable	231	161
Long Island Power Authority settlement	-	371

The accompanying notes are an integral part of these consolidated financial statements.

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31, 2015	March 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 453**	$ 1,594
Restricted cash and special deposits	**523**	168
Accounts receivable	**2,644**	2,762
Allowance for doubtful accounts	**(361)**	(300)
Other receivable	**-**	58
Accounts receivable from affiliates	**1**	1
Unbilled revenues	**567**	620
Inventory	**397**	344
Regulatory assets	**667**	571
Derivative contracts	**45**	140
Current portion of deferred income tax assets, net	**266**	137
Prepaid taxes	**318**	329
Other	**144**	125
Current assets related to discontinued operations	**70**	153
Total current assets	**5,734**	6,702
Equity investments	**190**	194
Property, plant, and equipment, net	**25,671**	23,875
Other non-current assets:		
Regulatory assets	**4,921**	4,322
Goodwill	**7,129**	7,151
Derivative contracts	**30**	66
Postretirement benefits asset	**189**	305
Financial investments	**494**	476
Other	**129**	142
Other non-current assets related to discontinued operations	**-**	29
Total other non-current assets	**12,892**	12,491
Total assets	**$ 44,487**	$ 43,262

The accompanying notes are an integral part of these consolidated financial statements.

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31, 2015	March 31, 2014
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 1,393**	$ 1,339
Accounts payable to affiliates	**63**	71
Advance from affiliate	**-**	750
Commercial paper	**582**	421
Current portion of long-term debt	**1,658**	2,231
Taxes accrued	**5**	21
Customer deposits	**120**	98
Interest accrued	**146**	143
Regulatory liabilities	**627**	524
Derivative contracts	**332**	43
Renewable energy certificate obligations	**166**	123
Payroll and benefits accruals	**252**	228
Other	**178**	216
Current liabilities related to discontinued operations	**21**	37
Total current liabilities	**5,543**	6,245
Other non-current liabilities:		
Regulatory liabilities	**2,864**	2,688
Asset retirement obligations	**81**	87
Deferred income tax liabilities, net	**4,852**	4,745
Postretirement benefits	**3,839**	2,872
Environmental remediation costs	**1,336**	1,341
Derivative contracts	**420**	14
Other	**921**	950
Total other non-current liabilities	**14,313**	12,697
Commitments and contingencies (Note 14)		
Capitalization:		
Shareholders' equity	**10,446**	10,298
Long-term debt	**14,185**	14,022
Total capitalization	**24,631**	24,320
Total liabilities and capitalization	**$ 44,487**	$ 43,262

The accompanying notes are an integral part of these consolidated financial statements.

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
(in millions of dollars)

			March 31, 2015	March 31, 2014
Shareholders' equity attributable to common and preferred shares			**$ 10,432**	$ 10,286
Non-controlling interest in subsidiaries			**14**	12
Long-term debt:	Interest Rate	Maturity Date		
European Medium Term Note	Variable	June 2015 - February 2022	**3,447**	2,515
Notes Payable	2.72% - 9.75%	October 2015 - December 2042	**6,338**	6,782
Gas Facilities Revenue Bonds	Variable	December 2020 - July 2026	**230**	230
Gas Facilities Revenue Bonds	4.7% - 6.95%	April 2020 - July 2026	**411**	411
First Mortgage Bonds	6.82% - 9.63%	April 2018 - April 2028	**125**	127
State Authority Financing Bonds	Variable	October 2015 - August 2042	**1,033**	1,153
Industrial Development Revenue Bonds	5.25%	June 2027	**128**	128
Intercompany Notes	Variable	August 2015 - August 2027	**4,138**	4,903
Total debt			**15,850**	16,249
Other			**(7)**	4
Current portion of long-term debt			**(1,658)**	(2,231)
Long-term debt			**14,185**	14,022
Total capitalization			**$ 24,631**	$ 24,320

The accompanying notes are an integral part of these consolidated financial statements.

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(in millions of dollars)

				Accumulated Other Comprehensive Income (Loss)							
	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Foreign Currency Translation	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest	Total
Balance as of March 31, 2013	**$ -**	**$ 35**	**$ 7,161**	**$ (2)**	**$ (864)**	**$ (2)**	**$ (139)**	**$ (1,007)**	**$ 2,238**	**$ 26**	**$ 8,453**
Net income	-	-	-	-				-	613	(20)	593
Other comprehensive income (loss):											
Unrealized gains on securities, net of $3 tax expense	-	-	-	4	-	-	-	4	-	-	4
Change in pension and other postretirement obligations, net of $148 tax expense	-	-	-	-	212	-	-	212	-	-	212
Unrealized gains on hedges, net of $3 tax expense	-	-	-	-	-	4	-	4	-	-	4
Total comprehensive income											813
Equity infusion from Parent	-	-	1,000	-	-	-	-	-	-	-	1,000
Share based compensation	-	-	33	-	-	-	-	-	-	-	33
Other equity transactions with non-controlling interest	-	-	(7)	-	-	-	-	-	-	6	(1)
Balance as of March 31, 2014	**$ -**	**$ 35**	**$ 8,187**	**$ 2**	**$ (652)**	**$ 2**	**$ (139)**	**$ (787)**	**$ 2,851**	**$ 12**	**$ 10,298**
Net income	-	-	-	-				-	361	(18)	343
Other comprehensive income (loss):											
Unrealized gains on securities, net of $4 tax expense	-	-	-	6	-	-	-	6	-	-	6
Change in pension and other postretirement obligations, net of $167 tax benefit	-	-	-	-	(238)	-	-	(238)	-	-	(238)
Unrealized gains on hedges, net of $3 tax expense	-	-	-	-	-	6	-	6	-	-	6
Total comprehensive income											117
Share based compensation	-	-	15	-	-	-	-	-	-	-	15
Other equity transactions with non-controlling interest	-	-	(4)	-	-	-	-	-	-	20	16
Balance as of March 31, 2015	**$ -**	**$ 35**	**$ 8,198**	**$ 8**	**$ (890)**	**$ 8**	**$ (139)**	**$ (1,013)**	**$ 3,212**	**$ 14**	**$ 10,446**

The Company had 1,353 shares of common stock authorized, issued and outstanding, with a par value of $0.10 per share and 372,641 shares of cumulative preferred stock authorized, issued and outstanding, with par values of $100 and $50 per share at March 31, 2015 and 2014.

The accompanying notes are an integral part of these consolidated financial statements.

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

National Grid North America Inc. ("NGNA" or "the Company") is a Delaware corporation that was created on May 16, 2001 to finance acquisitions in the United States ("U.S."). The Company is an indirect wholly-owned subsidiary of National Grid plc (the "Parent"), a public limited company incorporated under the laws of England and Wales. It is the intermediate holding company of National Grid USA ("NGUSA") and acts as a funding company on behalf of the Parent for certain subsidiaries' borrowings.

NGUSA has two major lines of business, "Gas Distribution" and "Electric Services," and operates various energy services and investment companies.

The Company's wholly-owned New England subsidiaries include: New England Power Company ("NEP"), The Narragansett Electric Company ("Narragansett"), Massachusetts Electric Company ("Massachusetts Electric"), Nantucket Electric Company ("Nantucket"), Boston Gas Company ("Boston Gas"), and Colonial Gas Company ("Colonial Gas"). The Company's wholly-owned New York subsidiaries include: Niagara Mohawk Power Corporation ("Niagara Mohawk"), National Grid Generation, LLC ("Genco"), The Brooklyn Union Gas Company ("Brooklyn Union"), and KeySpan Gas East Corporation ("KeySpan Gas East").

In addition, the Company has certain subsidiaries which have provided operational and energy management services and continue to supply capacity to and produce energy for the use of customers of the Long Island Power Authority ("LIPA"), on Long Island, New York. The services provided to LIPA were, or continue to be, provided through the following contractual arrangements. The Power Supply Agreement ("PSA"), which was amended and restated for a maximum term of 15 years in October 2012, provides LIPA with electric generating capacity, energy conversion and ancillary services from the Company's Long Island generating units. The Energy Management Agreement ("EMA"), which expired on May 28, 2013, provided management of all aspects of fuel supply for the Company's Long Island generating facilities. The Management Service Agreement ("MSA"), which expired on December 31, 2013, provided operation, maintenance and construction services, and significant administrative services relating to the Long Island electric transmission and distribution system. The results of the MSA are reflected as discontinued operations in the accompanying consolidated financial statements for the years ended March 31, 2015 and 2014.

Other Services and Investments

The Company's Energy Services business includes companies that provide energy-related services to customers located primarily within the northeastern U.S. These services comprise the operation, maintenance, and design of energy systems for commercial and industrial customers.

The Company's Energy Investments business consists of gas production and development investments such as natural gas pipelines, as well as certain other domestic energy-related investments. Through the Company's wholly-owned subsidiary, National Grid LNG, it owns a 600,000 barrel liquefied natural gas ("LNG") storage and receiving facility in Providence, Rhode Island. The Company also owns a 53.7% interest in two hydro-transmission electric companies which are consolidated into these financial statements.

The Company's consolidated financial statements also include a 26.25% interest in Millennium Pipeline Company LLC ("Millennium") and a 20.4% interest in Iroquois Gas Transmission System, which are accounted for under the equity method of accounting. In addition, the Company owns an equity ownership interest in three regional nuclear generating companies whose facilities have been decommissioned as discussed in Note 14, "Commitments and Contingencies" under "Decommissioning Nuclear Units."

On August 14, 2015, the Company entered into an agreement to exchange its 20.4% interest in Iroquois Gas Transmission System to Dominion Midstream Partners, LP ("DM") in exchange for approximately 6.8 million common units (representing approximately a 15% interest) in DM. DM owns, operates, develops and acquires natural gas import, storage, regasification, transportation and related assets, including a preferred equity interest in the Cove Point LNG facility in Lusby, Maryland and ownership of Carolina Gas Transmission ("CGT") in Cayce, South Carolina. Cove Point provides LNG import, storage and transportation services to the Mid-Atlantic marketplace and CGT is an interstate natural gas transportation company delivering natural gas to wholesale and direct industrial customers throughout South Carolina. This exchange transaction is expected to close by September 30, 2015.

Through its indirect wholly-owned subsidiary, National Grid Generation Ventures LLC, the Company owns a 50% interest in Island Park Energy Center LLC, formed to construct, install, hold, own, protect, finance, manage, operate and maintain projects consisting of the repowering of the E.F. Barrett Steam Unit and Barrett CT Units all located in Nassau County, New York.

Additionally, National Grid Generation Ventures LLC owns a 50% interest in three LLCs (LI Solar Generation LLC, LI Energy Storage System LLC, and LI Peaker Generation LLC). These LLCs were formed to jointly respond to LIPA's Request for Proposals ("RFP's") for Generation, Energy Storage and Demand Response Resources, and to jointly develop, construct, install, hold, own, protect, finance, manage, operate and maintain the respective RFP projects (none were awarded) or future proposals for similar projects.

Grid NY LLC, a direct wholly-owned subsidiary of Keyspan Corporation, was formed pursuant to the articles of organization filed on October 10, 2014 to own a 28.261% equity interest in New York Transco LLC ("NY Transco LLC"), a New York limited liability company, which was formed pursuant to the articles of organization filed on November 14, 2014 for the purpose of planning, construction, owning, operating, maintaining and expanding transmission facilities in the state of New York.

The Company uses the equity method of accounting for its investments in affiliates when it has the ability to exercise significant influence over the operating and financial policies, but does not control the affiliates. The Company's share of the earnings or losses of such affiliates is included as income from equity investments in the accompanying consolidated statements of income.

The accompanying consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"), including the accounting principles for rate-regulated entities as applicable. The consolidated financial statements reflect the ratemaking practices of the applicable regulatory authorities.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Non-controlling interests of majority-owned subsidiaries are calculated based upon the respective non-controlling interest ownership percentages. All intercompany transactions have been eliminated in consolidation.

Under its holding company structure, the Company has no independent operations or source of income of its own and conducts all of its operations through its subsidiaries. As a result, the Company depends on the earnings and cash flow of, and dividends or distributions from, its subsidiaries to provide the funds necessary to meet its debt and contractual obligations. Furthermore, a substantial portion of the Company's consolidated assets, earnings and cash flow is derived from the operations of its regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to the Company is subject to regulation by state regulatory authorities.

Management recorded out-of-period adjustments during the current fiscal year that resulted in an increase to net income from continuing operations of $5.9 million (net of income taxes). The adjustments primarily related to a $51.4 million increase to net income for the correction of the Company's methodology for accruing Niagara Mohawk and Narragansett property taxes, which were previously accrued on a calendar year basis; a $23.6 million increase to net income related to the correction of the Company's tax accounting for employee variable pay tax deduction, offset by an $18.1 million decrease to net income resulting from the recognition of a previously unrecognized regulatory liability for the Brooklyn Union and Niagara Mohawk Net Utility Plant Trackers; a $35.8 million decrease to net income resulting from the correction of the Company's accounting for its revenue decoupling mechanism ("RDM") related to the unbilled component of revenue;

a $6.4 million decrease to net income to correct the timing of recognition of rate resets and true-ups related to billings to LIPA under the terms of the PSA; a $5.3 million decrease to net income to correct the valuation of the liability associated with a historical lease agreement of KeySpan Corporation; combined with various other immaterial corrections totaling a decrease of $3.5 million. The adjustments primarily impacted operating revenues, other taxes and income tax expense. Management has concluded that the impact of recording these adjustments was not material to the current fiscal year or any prior period.

The Company has evaluated subsequent events and transactions through September 18, 2015, the date of issuance of these consolidated financial statements, and concluded that there were no events or transactions that require adjustment to, or disclosure in, the consolidated financial statements as of and for the year ended March 31, 2015, except as described in Note 19, "Subsequent Events."

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing consolidated financial statements that conform to U.S. GAAP, the Company must make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses, and the disclosure of contingent assets and liabilities included in the consolidated financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC"), the New York Public Service Commission ("NYPSC"), the Massachusetts Department of Public Utilities ("DPU"), and the Rhode Island Public Utilities Commission ("RIPUC") regulate the rates the Company's regulated subsidiaries charge their customers in the applicable states. In these cases, the subsidiaries defer costs (as regulatory assets) or recognize obligations (as regulatory liabilities) if it is probable that such amounts will be recovered from, or refunded to, customers through future rates. Regulatory assets and liabilities are amortized to the consolidated statements of income consistent with the treatment of the related costs in the ratemaking process. Iroquois' transmission assets are regulated by the Federal Energy Regulatory Commission ("FERC") and its rates are filed with the FERC.

Revenue Recognition

Electric and Gas Distribution Revenue

Revenues are recognized for energy service provided on a monthly billing cycle basis. The Company records unbilled revenues for the estimated amount of services rendered from the time meters were last read to the end of the accounting period.

As approved by state regulators, the Company is allowed to pass through commodity-related costs to customers and also bills for approved rate adjustment mechanisms. In addition, the Company's subsidiaries have revenue decoupling mechanisms which allow for adjustments to the Company's delivery rates as a result of the reconciliation between allowed revenue and billed revenue. Any difference between the allowed revenue and the billed revenue is recorded as a regulatory asset or regulatory liability.

The gas distribution business is influenced by seasonal weather conditions. Brooklyn Union, KeySpan Gas East, Niagara Mohawk and Narragansett gas utility tariffs contain weather normalization adjustments that provide for recovery from, or refund to, customers of material shortfalls or excesses of delivery revenues (revenues less applicable gas costs and revenue taxes) during a heating season due to variations from normal weather.

Transmission Revenue

Transmission revenues are generated by NEP, Narragansett, Massachusetts Electric, Nantucket, and Niagara Mohawk. Such revenues are based on a formula rate that recovers actual costs plus a return on investment. Stranded cost recovery revenues are collected through a contract termination charge ("CTC"), which is billed to former wholesale customers of the Company in connection with the Company's divestiture of its electricity generation investments.

Generation Revenue

Electric generation revenue is derived from billings to LIPA for the electric generation capacity and, to the extent requested, energy from the Company's existing oil and gas-fired generating plants as discussed in Note 14, "Commitments and Contingencies" under "Electric Services and LIPA Agreements."

Other Revenues

Revenues earned for service and maintenance contracts associated with commercial energy systems are recognized as earned or over the life of the service contract, as appropriate.

Other Taxes

The Company's subsidiaries collect taxes and fees from customers such as sales taxes, other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. The Company accounts for taxes that are imposed on customers (such as sales taxes) on a net basis (excluded from revenues), while taxes imposed on the Company, such as excise taxes, are recognized on a gross basis. Excise taxes collected and paid for the years ended March 31, 2015 and 2014 were $107.2 million and $103.4 million, respectively.

Gas distribution revenues include the collection of excise taxes and the related expense is included in other taxes in the accompanying consolidated statements of income.

The state of New York imposes on corporations a franchise tax that is computed as the higher of a tax based on income or a tax based on capital. To the extent the Company's New York state tax based on capital is in excess of the state tax based on income, the Company reports such excess in other taxes and taxes accrued in the accompanying consolidated financial statements.

Income Taxes

Federal and state income taxes have been computed utilizing the asset and liability approach that requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the consolidated financial statement carrying amounts and the tax basis of existing assets and liabilities. Deferred income taxes also reflect the tax effect of net operating losses, capital losses and general business credit carryforwards.

The effects of tax positions are recognized in the consolidated financial statements when it is more likely than not that the position taken, or expected to be taken, in a tax return will be sustained upon examination by taxing authorities based on the technical merits of the position. The financial effect of changes in tax laws or rates is accounted for in the period of enactment. Deferred investment tax credits are amortized over the useful life of the underlying property.

NGNA files consolidated federal tax returns including all of the activities of its subsidiaries. Each subsidiary company determines its current and deferred taxes based on the separate return method. Each subsidiary settles its current tax liability or benefit with NGNA in accordance with a tax sharing agreement between NGNA and its subsidiaries. In addition, certain consolidated tax benefits allocated from NGNA to its subsidiaries are treated as capital contributions.

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. Cash and cash equivalents are carried at cost which approximates fair value.

Restricted Cash and Special Deposits

Restricted cash primarily consists of deposits held by the New York Independent System Operator ("NYISO") and by the ISO New England ("ISO-NE") and cash collateral related to derivative contracts. Special deposits primarily consist of health care claims deposits. The Company had restricted cash of $502 million and $144 million and special deposits of $21 million and $24 million at March 31, 2015 and 2014, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based on a variety of factors including, for each type of receivable, applying an estimated reserve percentage to each aging category, taking into account historical collection and write-off experience and management's assessment of collectability from individual customers as appropriate. The collectability of receivables is continuously assessed and, if circumstances change, the allowance is adjusted accordingly. Receivable balances are written off against the allowance for doubtful accounts when the accounts are disconnected and/or terminated and the balances are deemed to be uncollectible.

Inventory

Inventory is comprised of materials and supplies, emission credits, renewable energy certificates ("RECs"), and gas in storage. Materials and supplies are stated at the lower of weighted average cost or market and are expensed or capitalized as used. The Company's policy is to write-off obsolete inventory; there were no material write-offs of obsolete inventory for the years ended March 31, 2015 or 2014. Emission credits are comprised of sulfur dioxide, nitrogen oxide ("NOx"), and carbon dioxide credits. Emission credits are held primarily for consumption or may be sold to third-party purchasers. RECs are used to measure compliance with renewable energy standards and are held primarily for consumption.

Gas in storage is stated at weighted average cost and the related cost is recognized when delivered to customers. Existing rate orders allow the Company to pass directly through to customers the cost of gas purchased, along with any applicable authorized delivery surcharge adjustments. Gas costs passed through to customers are subject to regulatory approvals and are reported periodically to the applicable state regulators.

At March 31, 2015 and 2014, the Company had materials and supplies of $158 million and $150 million, emission credits of $44 million and $28 million, gas in storage of $149 million and $111 million, and purchased RECs of $46 million and $55 million, respectively.

Derivative Contracts

The Company uses derivative contracts to manage commodity price risk, as well as interest and foreign currency rate risk. All derivative contracts are recorded in the accompanying consolidated balance sheets at their fair value. Qualifying derivative contracts may be designated as either cash flow hedges or fair value hedges.

Commodity Derivative Contracts

All commodity costs, including the impact of derivative contracts, are passed on to customers through the Company's commodity rate adjustment mechanisms. Therefore, gains or losses on the settlement of these contracts are initially deferred and then refunded to, or collected from, customers consistent with regulatory requirements.

Certain non-trading contracts for the physical purchase of natural gas and electricity qualify for the normal purchase normal sale exception and are accounted for upon settlement. If the Company were to determine that a contract for which it elected the normal purchase normal sale exception no longer qualifies, the Company would recognize the fair value of the contract in accordance with the regulatory accounting described above.

Financing Derivative Contracts

Treasury related derivative contracts may qualify as either fair value hedges or cash flow hedges. The Company has entered into cross-currency and interest rate swaps ("CCIRS") to protect against changes in the fair value of fixed-rate borrowings due to movements in market interest rates. The Company has designated these instruments as fair value hedging relationships. For qualifying fair value hedges, all changes in the fair value of the derivative financial instrument and changes in the fair value of the item in relation to the risk being hedged are recognized in the consolidated statements of income. If the hedge relationship is terminated, the fair value adjustment to the hedged item continues to be reported as part of the basis of the item and is amortized to the consolidated statements of income as a yield adjustment over the remainder of the hedging period. At March 31, 2015, the Company had $9 million of current derivative liabilities and $92 million of non-current derivative liabilities designated in fair value hedging relationships. At March 31, 2014, the Company had $10 million of non-current derivative assets designated in fair value hedging relationships.

The Company continually assesses the cost relationship between fixed and variable rate debt and periodically enters into CCIRS to convert the terms of the underlying debt obligations from fixed rate to variable rate or variable rate to fixed rate. Payments made, or received, on these derivative contracts are recognized as an adjustment to interest expense as incurred. The Company has designated these instruments as cash flow hedges. For qualifying cash flow hedges, the effective portion of a derivative's gain or loss is reported in other comprehensive income, net of related tax effects, and the ineffective portion is reported in earnings. Amounts in accumulated other comprehensive income ("AOCI") are reclassified into earnings in the same period or periods during which the hedged transaction affects earnings.

As of March 31, 2015, the Company had $2.5 billion of foreign currency debt and $2 million of current derivative assets, $212 million of current derivative liabilities and $274 million of non-current derivative liabilities designated in cash flow hedging relationships, with $8.2 million recognized in other comprehensive income for the year ended March 31, 2015. As of March 31, 2014, the Company had $3.1 billion of foreign currency debt and $75 million of current derivative assets and $30 million of non-current derivative assets designated in cash flow hedging relationships, with $6.3 million recognized in other comprehensive income for the year ended March 31, 2014. The Company expects no reclassification from other comprehensive income into earnings within the next twelve months. For the years ended March 31, 2015 and 2014, the Company recorded ineffectiveness related to cash flow hedges of $2.4 million (loss) and $4.2 million (loss), respectively.

The Company's accounting policy is to not offset fair value amounts recognized for derivative contracts and related cash collateral receivable or payable with the same counterparty under a master netting agreement, and to record and present the fair value of the derivative contract on a gross basis, with related cash collateral recorded within restricted cash and special deposits in the accompanying consolidated balance sheets.

Power Purchase Agreements

Certain of the Company's subsidiaries enter into power purchase agreements to procure commodity to serve their electric service customers. The Company evaluates whether such agreements are leases, derivatives, or executory contracts. Power purchase agreements that do not qualify as leases or derivatives are accounted for as executory contracts and are, therefore, recognized as the electricity is purchased. In making its determination of the accounting for power purchase agreements, the Company considers many factors, including: the source of the electricity; the level of output from any specified facility that the Company is taking under the contract; the involvement, if any, that the Company has in operating the specified facility; and the pricing mechanisms in the contract among other factors.

Fair Value Measurements

The Company measures derivatives and available-for-sale securities at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date;
- 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; and
- Level 3: unobservable inputs, such as internally-developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs.

The asset or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. The Company uses valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

Property, Plant and Equipment

Property, plant and equipment is stated at original cost. The cost of repairs and maintenance is charged to expense and the cost of renewals and betterments that extend the useful life of property, plant and equipment is capitalized. The capitalized cost of additions to property, plant and equipment includes costs such as direct material, labor and benefits, and an allowance for funds used during construction ("AFUDC") for the regulated subsidiaries and capitalized interest for non-regulated projects.

Depreciation is computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the state authorities. The average composite rates and average service lives for the years ended March 31, 2015 and 2014 are as follows:

	Electric		Gas		Common	
	Years Ended March 31,		Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014	**2015**	2014
Composite rates	**2.7%**	2.8%	**2.9%**	2.9%	**4.8%**	5.3%
Average service lives	48 years	48 years	**46 years**	46 years	**35 years**	36 years

Depreciation expense for regulated subsidiaries includes a component for estimated future cost of removal, which is recovered through rates charged to customers. Any difference in cumulative costs recovered and costs incurred is recognized as a regulatory liability. When property, plant and equipment is retired, the original cost, less salvage, is charged to accumulated depreciation, and the related cost of removal is removed from the associated regulatory liability. The Company had cumulative costs recovered in excess of costs incurred of $1.7 billion and $1.6 billion at March 31, 2015 and 2014, respectively.

Allowance for Funds Used During Construction

In accordance with applicable accounting guidance, the regulated subsidiaries record AFUDC, which represents the debt and equity costs of financing the construction of new property, plant and equipment. AFUDC equity is reported in the consolidated statements of income as non-cash income in other deductions, net, and AFUDC debt is reported as a non-cash offset to other interest, including affiliate interest. After construction is completed, the Company is permitted to recover these costs through their inclusion in rate base and corresponding depreciation expense. The Company recorded AFUDC related to equity of $19 million and $27 million for the years ended March 31, 2015 and 2014, respectively. The Company recorded AFUDC related to debt of $6 million and $13 million for the years ended March 31, 2015 and 2014, respectively. The average AFUDC rates for the years ended March 31, 2015 and 2014 were 2.7% and 4.5%, respectively.

In addition, approximately $0.8 million and $1.2 million of interest was capitalized for construction of non-regulated projects during the years ended March 31, 2015 and 2014, respectively.

Goodwill

The Company tests goodwill for impairment annually on January 1, and when events occur or circumstances change that would more likely than not reduce the fair value of each of the Company's respective reporting units below its carrying amount. Goodwill is tested for impairment using a two-step approach. The first step compares the estimated fair value of each reporting unit with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, then goodwill is considered not impaired. If the carrying value exceeds the estimated fair value, then a second step is performed to determine the implied fair value of goodwill. If the carrying value of goodwill exceeds its implied fair value, then an impairment charge equal to the difference is recorded.

The fair value of each reporting unit was calculated in the annual goodwill impairment test for the year ended March 31, 2015 utilizing both income and market approaches, except as it pertains to Clean Line Energy Partners LLC ("Clean Line") as described in Note 12, "Goodwill."

- To estimate fair value utilizing the income approach, the Company used a discounted cash flow methodology incorporating its most recent business plan forecasts together with a projected terminal year calculation. Key assumptions used in the income approach were: (a) expected cash flows for the period from April 1, 2015 to March 31, 2020; (b) a discount rate of 5.2%, which was based on the Company's best estimate of its after-tax weighted-average cost of capital; and (c) a terminal growth rate of 2.25%, based on the Company's expected long-term average growth rate in line with estimated long-term U.S. economic inflation.

- To estimate fair value utilizing the market approach, the Company followed a market comparable methodology. Specifically, the Company applied a valuation multiple of earnings before interest, taxes, depreciation and amortization ("EBITDA"), derived from data of publicly-traded benchmark companies, to business operating data. Benchmark companies were selected based on comparability of the underlying business and economics. Key assumptions used in the market approach included the selection of appropriate benchmark companies and the selection of an EBITDA multiple of 11, which the Company believes is appropriate based on comparison of its business with the benchmark companies.

The Company determined the fair value of the business using 50% weighting for each valuation methodology, as it believes that each methodology provides equally valuable information. Based on the resulting fair value from the annual analyses, the Company determined that no adjustment of the goodwill carrying value was required at March 31, 2015 or 2014, except in relation to Clean Line as described in Note 12, "Goodwill."

Prior to 2015, the Company utilized an annual impairment assessment date of January 31. Management has determined that the use of January 1 as its annual impairment assessment date is preferable to January 31 because it facilitates a more timely evaluation in advance of the Company's fiscal year end of March 31. The movement of the date has not resulted in a substantive change in the timing of recording any potential impairment.

Available-For-Sale Securities

The Company holds available-for-sale securities that include equities, municipal bonds and corporate bonds. These investments are recorded at fair value and are included in other non-current assets in the accompanying consolidated balance sheets. Changes in the fair value of these assets are recorded within other comprehensive income.

Asset Retirement Obligations

Asset retirement obligations are recognized for legal obligations associated with the retirement of property, plant and equipment, primarily associated with the Company's gas distribution and electric generation facilities. Asset retirement obligations are recorded at fair value in the period in which the obligation is incurred, if the fair value can be reasonably estimated. In the period in which new asset retirement obligations, or changes to the timing or amount of existing retirement obligations are recorded, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period the asset retirement obligation is accreted to its present value.

The Company has a legal obligation to dismantle the Glenwood and Far Rockaway facilities and remediate the associated sites. These facilities were shut down and decommissioning began in July 2012; demolition and remediation activities at Glenwood and Far Rockaway were completed in July 2015 and in August 2015, respectively.

The following table represents the changes in the Company's asset retirement obligations:

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 87**	$ 105
Accretion expense	**5**	6
Liabilities settled	**(11)**	(24)
Balance as of the end of the year	**$ 81**	$ 87

At March 31, 2015, the Company carried out a revaluation study that resulted in a net upward revaluation in estimated cost related to the asset retirement obligations. These increases were due to changes in remediation cost and enhanced asset replacement programs.

Accretion expense for the Company's regulated subsidiaries is deferred as part of the Company's asset retirement obligation regulatory asset as management believes it is probable that such amounts will be collected in future rates.

Employee Benefits

The Company has defined benefit pension and postretirement benefit other than pension ("PBOP") plans for its employees. The Company recognizes all pension and PBOP plans' funded status in the accompanying consolidated balance sheets as a net liability or asset with an offsetting adjustment to AOCI in shareholders' equity. In the case of regulated entities, the cost of providing these plans is recovered through rates; therefore, the net funded status is offset by a regulatory asset or liability. The Company measures and records its pension and PBOP funded status at the year-end date. Pension and PBOP plan assets are measured at fair value, using the year-end market value of those assets.

Supplemental Executive Retirement Plans

The Company has corporate assets included in financial investments in the accompanying consolidated balance sheets representing funds designated for Supplemental Executive Retirement Plans. These funds are invested in corporate owned life insurance policies and available-for-sale securities primarily consisting of equity investments and investments in municipal and corporate bonds. The corporate owned life insurance investments are measured at cash surrender value with increases and decreases in the value of these assets recorded in the accompanying consolidated statements of income.

New and Recent Accounting Guidance

Accounting Guidance Adopted in Fiscal Year 2015

Reclassifications From Accumulated Other Comprehensive Income

In February 2013, the FASB issued ASU 2013-02, "Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income," to improve the reporting of reclassifications out of AOCI. The amendments require an entity to provide information either on the face of the consolidated financial statements or in a single footnote on significant amounts reclassified out of AOCI and the related income statement line items to the extent an amount is reclassified in its entirety to net income. For significant items not reclassified to net income in their entirety, an entity is required to cross-reference to other disclosures that provide additional information. For non-public entities, the amendments are effective prospectively for reporting periods beginning after December 15, 2013. Early adoption is permitted. The Company adopted this guidance effective April 1, 2014 with no impact on its financial position, results of operations or cash flows.

Accounting Guidance Not Yet Adopted

Presentation of Financial Statements - Going Concern, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern

In August 2014, the FASB issued amendments on reporting about an entity's ability to continue as a going concern in ASU No. 2014-15, "Presentation of Financial Statements – Going Concern (Subtopic 205 - 40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern." The amendments provide guidance about management's responsibility to evaluate whether there is substantial doubt surrounding an entity's ability to continue as a going concern. If management concludes that substantial doubt exists, the amendments also require additional disclosures relating to management's evaluation and conclusion. The amendments are effective for the annual reporting period ending after December 15, 2016 and interim periods thereafter. The application of this guidance is not expected to have a material impact on the Company's financial position, results of operations and cash flows.

Revenue Recognition

In May 2014, the FASB and the International Accounting Standards Board jointly issued a new revenue recognition standard ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." The objective of the new guidance is to provide a single comprehensive revenue recognition model for all contracts with customers to improve comparability. The standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services in an amount that reflects the consideration the entity expects to receive. The new guidance must be adopted using either a full retrospective approach or a modified retrospective approach. For non-public entities, the new guidance is effective for periods beginning after December 15, 2018, with early adoption permitted for periods beginning after December 15, 2017. The Company is currently evaluating the impact of the new guidance on its financial position, results of operations and cash flows.

3. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the ratemaking process. The following table presents the regulatory assets and regulatory liabilities recorded in the accompanying consolidated balance sheets.

		March 31,	
		2015	2014
		(in millions of dollars)	
Regulatory assets			
Current:			
	Derivative contracts	**$ 113**	$ 16
	Energy efficiency	**55**	23
	Gas costs adjustment	**131**	287
	Rate adjustment mechanisms	**87**	72
	Renewable energy certificates	**120**	91
	Revenue decoupling mechanism	**72**	20
	Transmission service	**63**	38
	Other	**26**	24
	Total	**667**	571
Non-current:			
	Environmental response costs	**1,732**	1,739
	Postretirement benefits	**2,070**	1,476
	Storm costs	**339**	319
	Other	**780**	788
	Total	**4,921**	4,322
Regulatory liabilities			
Current:			
	CTC decommissioning rebate	**-**	58
	Derivative contracts	**22**	50
	Energy efficiency	**130**	146
	Gas costs adjustment	**72**	50
	Profit sharing	**46**	38
	Rate adjustment mechanisms	**179**	68
	Revenue decoupling mechanism	**119**	66
	Temporary state assessment	**46**	-
	Other	**13**	48
	Total	**627**	524
Non-current:			
	Carrying charges	**145**	60
	Cost of removal	**1,683**	1,617
	Environmental response costs	**145**	104
	Postretirement benefits	**145**	220
	Temporary state assessment	**-**	111
	Other	**746**	576
	Total	**2,864**	2,688
	Net regulatory assets	**$ 2,097**	$ 1,681

Cost of removal: Represents cumulative amounts collected, but not yet spent, to dispose of property, plant and equipment. This liability is discharged as removal costs are incurred.

CTC decommissioning rebate: Represents the U.S. Department of Energy ("DOE") litigation awards for spent fuel storage costs that had been incurred through 2001 and 2008. These decommissioning rebates will be returned to customers through CTC charges.

Derivative contracts: The Company evaluates open derivative contracts for regulatory deferral by determining if they are probable of recovery from, or refund to, customers through future rates. Derivative contracts that qualify for regulatory deferral are recorded at fair value, with changes in fair value recorded as regulatory assets or regulatory liabilities in the period in which the change occurs.

Energy efficiency: Represents the difference between revenue billed to customers through the Company's energy efficiency charge and the costs of its energy efficiency programs as approved by the state authorities.

Environmental response costs: The regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates.

The regulatory liability primarily represents the amount of customer contributions and insurance proceeds recovered to pay for costs to investigate and perform certain remediation activities at sites with which it may be associated as well as the excess of amounts received in rates over the Company's actual site investigation and remediation ("SIR") costs.

Gas costs adjustment: The Company's gas regulated subsidiaries are subject to rate adjustment mechanisms for commodity costs, whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by state regulators. These amounts will be refunded to, or recovered from, customers over the next year.

Postretirement benefits: The amount in regulatory assets primarily represents the excess costs of the Company's pension and PBOP plans over amounts received in rates that are deferred to a regulatory asset to be recovered in future periods and the non-cash accrual of net actuarial gains and losses. The amount in regulatory liabilities primarily represents the excess of amounts received in rates over actual costs of the Company's pension and PBOP plans to be refunded in future periods.

Profit sharing: Represents a portion of deferred margins from off-system sale transactions. Under current rate orders, the Boston Gas and Colonial Gas (the "Massachusetts Gas Companies") are required to return 90% of margins earned from such optimization transactions to firm customers. The amounts deferred in the accompanying consolidated balance sheet will be refunded to customers over the next year.

Rate adjustment mechanisms: The Company's regulated subsidiaries are subject to a number of rate adjustment mechanisms such as for commodity costs, whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by the applicable state regulatory bodies.

Renewable energy certificates: Represents deferred costs associated with the Company's compliance obligation with the Rhode Island and Massachusetts Renewable Portfolio Standard ("RPS"). The RPS is legislation established to foster the development of new renewable energy sources. The regulatory asset will be recovered over the next year.

Revenue decoupling mechanism: Revenue decoupling mechanisms allow for the periodic adjustment of delivery rates as a result of the reconciliation between allowed revenue per customer and actual revenue per customer. Any difference between the allowed revenue per customer and the actual revenue per customer is recorded as a regulatory asset or regulatory liability.

Storm costs: Represents the incremental operation and maintenance costs to restore power to customers resulting from major storms.

Temporary state assessment: In June 2009, the NYPSC authorized utilities to recover the costs required for payment of the Temporary State Energy & Utility Service Conservation Assessment ("Temporary State Assessment"), including carrying charges. The Temporary State Assessment is subject to reconciliation over a five year period which began July 1, 2009.

On June 18, 2014, the NYPSC issued an order authorizing certain utilities, including Brooklyn Union and KeySpan Gas East ("The New York Gas Companies"), to recover the Temporary State Assessment subject to reconciliation, including carrying charges, from July 1, 2014 through June 30, 2017. As of March 31, 2015, the New York Gas Companies over-collected on these costs. The New York Gas Companies are required to net any deferred over-collected amounts against the amount to be collected during fiscal years 2014 and 2015 as well as the first payment relating to fiscal years 2015 and 2016.

On September 13, 2013 and August 7, 2013, Niagara Mohawk submitted a compliance filing (updated from June 14, 2013) proposing to maintain the currently effective surcharge. On June 18, 2014, a final order implementing a revised Temporary State Assessment resulted in a $2.7 million and $3.9 million credit to electric and gas customers, respectively, for rates effective July 1, 2014 through June 30, 2015.

Transmission service: The Company arranges transmission service on behalf of its customers' and bills the costs of those services to customers pursuant to the Company's Transmission Service Cost Adjustment Provision. Any over or under recoveries of these costs are passed on to customers receiving transmission service through the Company over the subsequent twelve months.

The Company records carrying charges on all regulatory balances (with the exception of derivative contracts, cost of removal, environmental response costs, renewable energy certificates, and regulatory deferred tax balances), for which cash expenditures have been made and are subject to recovery, or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made.

4. RATE MATTERS

Niagara Mohawk

March 2013 Electric and Gas Filing

In March 2013 the NYPSC issued a final order regarding Niagara Mohawk's electric and gas base rate filing made on April 27, 2012. The term of the new rate plan is from April 1, 2013 through March 31, 2016 and provides for an electric revenue requirement of $1,338.3 million in the first year, $1,395.9 million in the second year, and $1,432.5 million in the third year. It also provides for a gas revenue requirement of $307.4 million in the first year, $314.7 million in the second year, and $322 million in the third year.

Transmission Return on Equity Complaint

On September 11, 2012, the New York Association of Public Power ("NYAPP") filed a complaint against the Company, seeking to have the base ROE for transmission service of 11.5%, which includes a NYISO participation incentive adder, lowered to 9.49%. Similarly, on November 2, 2012 the Municipal Electric Utilities Association ("MEUA") filed a complaint to lower the Company's ROE to 9.25% including the NYISO participation adder. The MEUA complaint also challenged certain aspects of the Company's transmission formula rate. On February 6, 2014, the NYAPP filed a further complaint to reduce the ROE used in calculating rates for transmission service under the NYISO Open Access Transmission Tariff ("OATT") to 9.36%, inclusive of the 50 basis point adder for participation in the NYISO, with a corresponding overall weighted cost of capital of 6.60%. On February 24, 2015, the parties filed a Settlement Agreement which reduces the ROE used in calculating rates for transmission service under the NYISO OATT to 10.3%, inclusive of incentive adders, from November 2, 2012, until the date of a FERC order accepting the Settlement Agreement, and prospectively thereon. The Settlement Agreement also provides for a one-time refund of $180,000 plus interest on that amount calculated at the FERC rate pursuant to 18 C.F.R. §35.19a(a)(2)(iii) from November 2, 2012, until the date the refund is provided, along with a one-time refund of $200,000 without interest for the non-ROE transmission formula rate issues raised in the MEUA complaint. Any change in the ROE would not have an impact on net income as the retail rate plan fully reconciles any increase or decrease in wholesale transmission revenue under the FERC Transmission Service Charge rate through a Transmission Revenue Adjustment Clause mechanism. On May 13, 2015, the FERC issued a letter order approving the Company's Transmission ROE settlement without any modification.

Wholesale Transmission Service Charge

On December 6, 2013, Niagara Mohawk submitted a filing for FERC approval of revisions to its Wholesale Transmission Service Charge ("TSC Rate") under the NYSIO OATT to recover its RSS costs under two agreements with NRG to support the reliability of Niagara Mohawk's transmission system while transmission reinforcements are constructed. On February 4, 2014 the FERC allowed the RSS charges to become effective in TSC Rates as of July 1, 2013, subject to refund and further consideration of the matter by the FERC. On March 19, 2015, the FERC issued two orders relating to the Company's December 6, 2013 filing of proposed tariff revisions to the TSC Rate. In the first order, the FERC set for hearing and settlement judge procedures the justness and reasonableness of the Company's proposed Wholesale TSC formula rate revisions and the Dunkirk RSS charges. In the second order, the FERC rejected a request for rehearing filed by the MEUA regarding the FERC's decision to accept the December 6, 2013 amendment for filing retroactive to July 1, 2013. The FERC held the hearing on the first order in abeyance pending the outcome of settlement proceedings before a settlement judge.

Dunkirk RSS Agreement Extension

On May 18, 2015, the NYPSC approved a seven-month extension of the existing RSS agreement between the Company and Dunkirk. The approval extends the end date of the RSS from May 31, 2015 to December 31, 2015, and provides for recovery of the RSS costs under the surcharge mechanism currently in place. The extension is needed to address reliability issues until the Company's Five Mile Road substation and associated reconductoring projects are in service (estimated at December 31, 2015).

Management Audit

In February 2011, the NYPSC selected Overland Consulting Inc., ("Overland") to perform a management audit of NGUSA's affiliate cost allocations, policies and procedures. Niagara Mohawk and the New York Gas Companies disputed certain of Overland's final audit conclusions and the NYPSC ordered that further proceedings be conducted to address what, if any, ratemaking adjustments were necessary. On September 5, 2014, the NYPSC approved a settlement that resolves all outstanding issues relating to the audit and provides for no rate adjustments for the Company.

Gas Management Audit

In February 2013, the NYPSC initiated a comprehensive management and operational audit of NGUSA's New York gas businesses, including Niagara Mohawk and the New York Gas Companies, pursuant to the Public Service Law requirement that major electric and gas utilities undergo an audit every five years. The audit commenced in August 2013 and the NYPSC issued an audit findings repot in October 2014. The audit findings found that NGUSA's New York gas businesses performed well in providing reliable gas service, and strength in operations, network planning, project management, work management, load forecasting, supply procurement and customer systems support. Also included were 31 recommendations for improvement, including: reconstituting the boards of directors of NGUSA and the gas companies in New York to include more objective oversight; establishing stronger reporting authority between the New York jurisdictional president and operational organizations; preparing a true strategic plan for NGUSA's New York gas business operations to serve as a road map for investments, programs and operations to build upon the state energy plan and energy initiatives; developing a five-year, integrated, system-wide plan that includes all gas reliability work, mandated replacements, growth projects and system planning work, enhancing internal service level agreements to promote accountability for performance and costs; and undertaking a full accounting of all costs associated with NGUSA's SAP enterprise wide system. In November 2014, the Company filed joint audit implementation plans addressing each of the audit recommendations. On May 14, 2015, the NYPSC issued an order accepting without modifications the joint implementation plans and directing NGUSA's New York gas businesses to execute the plans.

Operations Audit

In August 2013, the NYPSC initiated an operational audit to review the accuracy of the customer service, electric reliability, and gas safety data reported by the investor owned utilities operating in New York, including Niagara Mohawk and the New York Gas Companies. On December 19, 2013, the NYPSC selected Overland to conduct the audit, which commenced in February 2014. At the time of the issuance of these consolidated financial statements, the Company has not received the final audit findings and cannot predict the outcome of this audit.

Operations Staffing Audit

In January 2014, the NYPSC initiated an operational audit to review internal staffing levels and use of contractors for the core utility functions of the investor owned utilities operating in New York, including Niagara Mohawk. On June 26, 2014, the NYPSC selected The Liberty Consulting Group to conduct the audit. At the time of the issuance of these consolidated financial statements, Niagara Mohawk cannot predict the outcome of this operational audit.

Recovery of Deferral Costs Relating to Emergency Order

On January 28, 2014, Niagara Mohawk filed a petition requesting a waiver of Rule 46.3.2 of its tariff. Rule 46.3.2 describes the manner in which Niagara Mohawk calculates its supply-related Mass Market Adjustment ("MMA"). Niagara Mohawk proposed the waiver of the rule to mitigate adverse financial impacts anticipated from a significant and unusual increase in electric commodity prices for its mass market customers.

On that same date, the NYPSC issued, on an emergency basis pursuant to the State Administrative Procedure Act §202(6), an Emergency Order granting Niagara Mohawk's waiver request (the "Emergency Order"). In the Emergency Order, the NYPSC waived the requirements of Rule 46.3.2 and approved deferral treatment of the costs and associated carrying charges related to the one-time credit provided via the waiver. However, the NYPSC denied, pending further review and consideration of public comments, Niagara Mohawk's request to recover such deferral over a six-month period beginning May 2014.

The NYPSC issued another order on April 25, 2014 permanently approving the Emergency Order and authorizing Niagara Mohawk to collect $33.3 million, plus carrying charges at the customer deposit rate, over a six-month period commencing with the June 2014 billing period. The deferral recovery will be performed in a manner consistent with the method that was used to provide the benefit to the mass market customers, through an adjustment to the MMA as calculated by NYISO load zone.

Petition for Authorization to Defer an Actuarial Experience Pension Settlement Loss for the Year Ending March 31, 2014

On February 28, 2014 and August 13, 2014 the Company filed petitions seeking authorization to defer $14.1 million related to a pension settlement loss incurred during the year ending March 31, 2014.

Commodity Rate Mechanism Changes

On October 23, 2014, the NYPSC approved tariff revisions filed by Niagara Mohawk that modified several components of Rule 46 – Supply Service Charges of Niagara Mohawk's tariff, NYPSC No. 220-Electricity. The revisions provide Niagara Mohawk with a measure of flexibility to manage significant volatility resulting from the reconciliation of commodity costs, like those experienced in January and March of 2014 due to the unanticipated extreme cold weather, for its residential and small commercial customers ("mass market customers"). The tariff revisions went into effect October 29, 2014 and will allow for more flexibility in the timing of Niagara Mohawk's reconciliation of revenues and expenses for mass market customers.

The New York Gas Companies

General Rate Case

KeySpan Gas East has been subject to a rate plan with a primary term of five years (2008-2012), which remains in effect until modified by the NYPSC. Under this rate plan, base delivery rates include an allowed ROE of 9.8% with a 45% equity ratio in the capital structure.

On June 13, 2013, the NYPSC approved a rate plan extension covering Brooklyn Union's 2013 and 2014 rate years. Brooklyn Union's revenue requirements for both years have been modified as follows: (i) there is no change in base delivery rates, other than those previously approved by the NYPSC in the rate plan extension, (ii) the allowed ROE has decreased from 9.8% to 9.4%, and (iii) the common equity ratio in the capital structure has increased from 45% to 48%.

Capital Investment

On June 13, 2014, KeySpan Gas East filed a petition with the NYPSC to implement a three year capital investment program that would allow KeySpan Gas East to invest more than $700 million in gas infrastructure projects designed to enhance the safety and reliability of its gas systems and promote gas growth, while maintaining base delivery rates.

On December 15, 2014, KeySpan Gas East received an order which authorizes it to replace leak prone pipe up to its forecasted budget of $211.7 million for calendars years 2015 and 2016. KeySpan Gas East is allowed to establish a 21-month surcharge mechanism beginning April 2, 2015 through December 31, 2016, which will be capped at $10 million and $13.4 million, respectively, to address KeySpan Gas East's capital needs for replacement of leak prone pipe, while minimizing future customer bill impacts. KeySpan Gas East was authorized to spend up to its forecasted budget of $202.7 million for calendar years 2015 and 2016 for its Neighborhood Expansion and other related programs. KeySpan Gas East is directed to establish a new deferral mechanism that allows it to defer the pre-tax revenue requirements associated with its capital spending program up to a maximum capital expenditure of $202.7 million made in calendar years 2015 and 2016. KeySpan Gas East's existing city/state deferral mechanism was eliminated as of January 1, 2015 and the non-growth deferral mechanism is continued. The order also included additional obligations and filing requirements.

Capital Reconciliation Mechanism Petition

In June 2015, Brooklyn Union submitted a petition to the NYPSC requesting a modification to the Capital Expenditures and Net Utility Plant and Depreciation Expense Reconciliation Mechanism ("Capital Reconciliation Mechanism") in its current rate plan. The Capital Reconciliation Mechanism is a downward only net utility plant reconciliation mechanism that permits a cumulative, two-year reconciliation for the two years ended December 31, 2014 and annual reconciliations thereafter. While Brooklyn Union implemented and largely completed its capital program for 2013 and 2014, its ability to launch certain programs was hampered by Superstorm Sandy and its aftermath. The impact of these delays and other related issues was a deferred liability, which was offset against the regulatory asset recorded in relation to the primary term of the rate plan. The requested modification to the Capital Reconciliation Mechanism would provide for an additional two year reconciliation period (calendar years 2015 and 2016) to complete more capital projects and facilitate Brooklyn Union's plan to invest in its distribution system infrastructure.

Massachusetts Electric and Nantucket (the "Massachusetts Electric Companies")

2009 Capital Investments Audit

The DPU approved an RDM arising from the 2009 distribution rate case filed by the Massachusetts Electric Companies. As part of their RDM provision, the Massachusetts Electric Companies file a report by July 1st of each year on their capital investment for the prior calendar year. In connection with the Massachusetts Electric Companies' first capital expenditure

("CapEx") filing made in July 2010, the DPU opened a proceeding in March 2011, as requested by the Massachusetts Attorney General's Office ("Attorney General"), for an independent audit of the Massachusetts Electric Companies' 2009 capital investments which, in part, formed the basis for the Massachusetts Electric Companies' RDM rate. On July 31, 2014, the DPU issued an order approving the sole respondent's bid to perform the CapEx audit. The CapEx audit is currently underway. The Massachusetts Electric Companies cannot currently predict the outcome of this proceeding.

Cost Recovery

In addition to the rates and tariffs put into effect following its most recent rate case, Massachusetts Electric continues to be authorized to recover costs associated with the procurement of electricity for its customers, all transmission costs, and costs charged by Massachusetts Electric's affiliate NEP, for stranded costs associated with NEP's former electric generation investments.

DPU Audit Settlement Agreement

In the general rate case involving the Company's Massachusetts gas distribution subsidiaries, the DPU opened an investigation to address the allocation and assignment of costs to the gas affiliates by the NGUSA service companies. The audit was later expanded to include the Massachusetts Electric Companies. The Massachusetts Electric Companies, the Massachusetts Gas Companies and the Attorney General's Office executed a Settlement Agreement that the DPU approved on July 25, 2014. As a result of the approval of the Settlement, there is no need for an audit, and both the Massachusetts Gas and Massachusetts Electric Companies will implement reporting and review practices similar to those in place for their New York affiliates, and NGUSA contributed $1 million to the Massachusetts Association for Community Action that will be used for the benefit of the Massachusetts Electric Companies' electric customers and the customers of its Massachusetts gas distribution affiliates who are eligible for fuel assistance.

Storm Management Audit

In January 2011, the DPU opened an investigation into the Massachusetts Electric Companies' preparation and response to a December 2010 winter storm. The DPU has the authority to issue fines not to exceed approximately $0.3 million for each violation for each day that the violation persists. On September 22, 2011, the DPU approved a settlement between Massachusetts Electric Companies and the Attorney General that included a $1.2 million refund to customers. The DPU also investigated the Massachusetts Electric Companies' response to Tropical Storm Irene and the October 2011 winter storm in a consolidated proceeding. On December 11, 2012, the DPU issued an order in which it assessed the Massachusetts Electric Companies a penalty of $18.7 million associated with the Massachusetts Electric Companies' performance in responding to these two weather events, consisting of $8.1 million for Tropical Storm Irene and $10.6 million for the October 2011 winter storm. The Massachusetts Electric Companies appealed this ruling and on September 4, 2014 the Court affirmed all but two violations, reducing the penalty by $0.9 million. The Massachusetts Electric Companies had recorded the original penalty and credited customers during March 2013. In addition, in the December 11, 2012 order, the DPU ordered a management audit of the Massachusetts Electric Companies' emergency planning, outage management, and restoration. The auditors have completed their audit, and submitted their Final Report to the DPU on July 9, 2014. The DPU adopted the auditor's thirty recommendations, which include items such as improving emergency response training and tracking of training, designating additional personnel for storm roles, and considering the expanded use of technology and communication tools. The Massachusetts Electric Companies have already implemented some of the recommendations and are in the process of implementing the remaining recommendations.

Storm Cost Recovery

The Massachusetts Electric Companies have deferred incremental storm costs of approximately $146 million as of March 31, 2015, net of customer contributions of approximately $95 million to the Massachusetts Electric Companies' Storm Contingency Fund, to restore power associated with several major weather events occurring since January 2010, pending ultimate approval by the DPU to charge its deferred costs to the Massachusetts Electric Companies' Storm Contingency Fund. This amount represents approximately $241 million of deferred storm costs, excluding net carrying costs of approximately $40 million. The deferred incremental storm cost and carrying cost amounts have been reduced by approximately $21 million and $2 million, respectively, to reflect the impact of estimated billings to Verizon for vegetation management costs as a result of the DPU's order regarding the December 2008 Storm. On March 5, 2013, the Massachusetts Electric Companies filed with the DPU a request for accelerated funding for the Massachusetts Electric Companies' Storm Contingency Fund of $40 million per year over a period of up to five years, or $200 million. On May 3, 2013, the DPU approved $40 million annually for up to three years, or $120 million. This is in addition to $4.3 million that the Massachusetts Electric Companies recover annually in base rates for the Storm Contingency Fund. In its ruling, the DPU also directed the Massachusetts Electric Companies to submit two filings of all documentation supporting its storm costs for DPU review and approval. The Massachusetts Electric Companies submitted the first filing for $128 million of costs on May 31, 2013 for qualifying storms that occurred during calendar years 2010 and 2011. On September 30, 2014, the Massachusetts Electric Companies submitted its second filing supporting $94 million of storm costs (net of $7 million of vegetation management costs billable to Verizon) that were incurred for storm events which occurred during calendar year 2012 through February 2013 and two additional storm events occurring in February and March 2013. In its September 30, 2014 filing, the Massachusetts Electric Companies also updated the costs related to the calendar year 2010 and 2011 storm events to exclude $10 million of vegetation management costs billed to Verizon. The Massachusetts Electric Companies cannot currently predict the outcome of any proceedings related to storm recovery.

The DPU's disallowance of vegetation management costs attributable to Verizon resulted in an over-recovery of costs related to the December 2008 ice storm as of April 30, 2014. Consequently, on May 14, 2014, the Massachusetts Electric Companies proposed to terminate the recovery related to the December 2008 ice storm in its current form effective July 1, 2014 and to combine approximately $7 million it has been recovering annually with the $40 million of annual accelerated Storm Contingency Fund recovery through the remainder of the three-year period. The DPU approved the Massachusetts Electric Companies' request on June 30, 2014. In addition, on August 29, 2014, the Massachusetts Electric Companies submitted a final reconciliation of the December 2008 ice storm recoveries, which resulted in an over-recovery of $1.6 million at June 30, 2014. The Massachusetts Electric Companies proposed to credit the Storm Contingency Fund for the $1.6 million balance, which the DPU approved on March 11, 2015.

2010 Service Quality Report

On December 30, 2013, the DPU issued an order on Massachusetts Electric's calendar year 2010 Service Quality Report, ordering that Massachusetts Electric refund to customers a net penalty of $6.7 million. On January 21, 2014, Massachusetts Electric filed a Motion for Clarification/Reconsideration regarding a portion of the penalty amount related to Circuit Average Interruption Frequency Index which totaled $2.7 million. In addition, Massachusetts Electric filed a proposal to credit customers the $6.7 million penalty along with a proposed tariff that would allow for recovery of the $2.7 million if the DPU ruled in favor of Massachusetts Electric regarding the Motion for Clarification/Reconsideration. On May 21, 2014, the DPU denied Massachusetts Electric's motion.

The Massachusetts Gas Companies

General Rate Case

In November 2010, the DPU issued an order in the Massachusetts Gas Companies' 2010 rate case approving a revenue increase of $58 million based upon a 9.75% ROE and a 50% equity ratio. The Massachusetts Gas Companies filed two motions in response. These motions resulted in a final revenue increase of $65.3 million reflected in rates effective February 1, 2013.

PBOP Carrying Charges

On June 1, 2011, in conjunction with the DPU's annual investigation of Boston Gas' calendar year 2009 pension and PBOP rate reconciliation mechanism, the Massachusetts Attorney General ("AG") argued that Boston Gas be obligated to provide carrying charges to the benefit of customers on its PBOP liability balances related to its 2003 to 2006 rate reconciliation filings. In August 2010, the DPU ordered Boston Gas to provide carrying charges on its PBOP liability balances on its 2007 and 2008 rate reconciliation filings, but the order was silent about providing carrying charges prior to those years. On

August 29, 2014, the DPU ordered Boston Gas to provide carrying charges on its 2003 to 2006 PBOP liability balances in its next annual pension and PBOP reconciliation filing. On September 15, 2014, the 2014-2015 Pension Adjustment Factor filing was finalized and Boston Gas recorded an $8.3 million reduction to the regulatory asset in the accompanying consolidated financial statements.

Gas System Enhancement Plan

On April 30, 2015, the DPU approved the Massachusetts Gas Companies' first Gas System Enhancement Plan for calendar year 2015 and the associated factors ("GSEAFs"). The approved GSEAFs are designed to provide concurrent recovery of the revenue requirement associated with the Massachusetts Gas Companies' capital costs for the replacement of eligible leak prone pipe and ancillary equipment pursuant to the 2014 Gas Leaks Act passed in Massachusetts. This new program will replace the currently effective Targeted Infrastructure Replacement Program. The approved GSEAFs are designed to recover from all firm sales and transportation customers a surcharge of approximately $9.7 million.

New England Power

Stranded Cost Recovery

Under settlement agreements approved by state commissions and the FERC, NEP is permitted to recover stranded costs (those costs associated with its former generating investments (nuclear and non-nuclear) and related contractual commitments that were not recovered through the sale of those investments). NEP earns an ROE of approximately 11% on stranded cost recovery. NEP will recover its remaining non-nuclear stranded costs through 2020. See the "Decommissioning Nuclear Units" in Note 14 "Commitments and Contingencies," for a discussion of ongoing costs associated with decommissioned nuclear units.

Transmission Return on Equity

NEP's transmission rates applicable to transmission service through October 15, 2014 reflect a base ROE of 11.14% applicable to NEP's transmission facilities, plus an additional 0.5% Regional Transmission Organization ("RTO") participation adder applicable to transmission facilities included under the Regional Network Service ("RNS") rate. Approximately 70% of the NEP's transmission facilities are included under RNS rates. NEP earns an additional 1% ROE incentive adder on RNS-related transmission facilities approved under the RTO's Regional System Plan and placed in service on or before December 31, 2008. It also earns a 1.25% ROE incentive on its portion of New England East-West Solution ("NEEWS") as described below. Effective as of October 16, 2014, the FERC issued a series of orders as the result of a ROE complaint case (see the "FERC ROE Complaints" in Note 14, "Commitments and Contingencies") reducing NEP's base ROE to 10.57%. The FERC also established a maximum ROE such that the aforementioned incentives, taken together, may not exceed a cap of 11.74%.

New England East-West Solution

In September 2008, NEP, its affiliate Narragansett, and Northeast Utilities jointly filed an application with the FERC to recover financial incentives for the NEEWS, pursuant to the FERC's Transmission Pricing Policy Order No. 679. Effective November 2008, the FERC granted (1) an incentive ROE of 12.89% (125 basis points above the approved base ROE of 11.64% including the RTO participation adder), (2) 100% construction work in progress in rate base and (3) recovery of plant abandoned for reasons beyond the companies' control. Effective October 16, 2014, the FERC issued a series of orders establishing a maximum ROE of 11.74% that effectively caps the NEEWS incentive ROE at that level.

Narragansett

General Rate Case

On April 11, 2013, the RIPUC issued an order approving the agreement among the Rhode Island Division of Public Utilities and Carriers, the Department of the Navy, and Narragansett, which provided for an increase in electric base distribution revenue of $21.5 million and an increase in gas base distribution revenue of $11.3 million based on a 9.5% allowed ROE and a common equity ratio of approximately 49.1%, effect retroactively on February 1, 2013. The order also included reinstatement of base rate recovery of storm fund contributions and implementation of a Pension Adjustment Mechanism for pension and PBOP expenses for the electric business identical to the mechanism in place for the gas business.

5. PROPERTY, PLANT AND EQUIPMENT

The following table summarizes property, plant and equipment at cost along with accumulated depreciation and amortization:

	March 31,	
	2015	2014
	(in millions of dollars)	
Plant and machinery	**$ 28,980**	$ 27,034
Property held for future use	**15**	16
Land and buildings	**2,108**	2,075
Assets in construction	**1,581**	1,410
Software and other intangibles	**792**	637
Total property, plant and equipment	**33,476**	31,172
Accumulated depreciation and amortization	**(7,805)**	(7,297)
Property, plant and equipment, net	**$ 25,671**	$ 23,875

6. DERIVATIVE CONTRACTS AND HEDGING

The Company utilizes derivative contracts to manage commodity price, interest and currency rate risk associated with its natural gas and electricity purchases and its foreign currency borrowings. The Company's commodity risk management strategy is to reduce fluctuations in firm gas and electricity sales prices to its customers. The Company's interest rate risk management strategy is to minimize its cost of capital. The Company's currency rate risk management policy is to hedge the risk associated with its foreign currency borrowings by utilizing instruments to convert principle and interest payments into U.S. dollars.

The Company's financial exposures are monitored and managed as an integral part of the Company's overall financial risk management policy. The Company engages in risk management activities only in commodities and financial markets where it has an exposure, and only in terms and volumes consistent with its core business.

Volumes

Volumes of outstanding commodity derivative contracts measured in dekatherms ("dths") and megawatt hours ("mwhs") are as follows:

	Electric		Gas	
	March 31,		March 31,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Gas swap contracts (dths)	**-**	-	**65**	50
Gas future contracts (dths)	**-**	-	**20**	20
Gas option contracts (dths)	**-**	-	**4**	23
Gas purchase contracts (dths)	**-**	-	**55**	87
Electric swap contracts (mwhs)	**11**	7	**-**	-
Total	**11**	7	**144**	180

Amounts Recognized in the Accompanying Consolidated Balance Sheets

	Asset Derivatives			Liability Derivatives	
	March 31,			March 31,	
	2015	2014		**2015**	2014
	(in millions of dollars)			*(in millions of dollars)*	
Current assets:			Current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas swap contracts	**$ 2**	$ 12	Gas swap contracts	**$ 37**	$ 4
Gas future contracts	**-**	3	Gas future contracts	**11**	1
Gas option contracts	**-**	2	Gas option contracts	**-**	1
Gas purchase contracts	**18**	11	Gas purchase contracts	**10**	36
Electric swap contracts	**23**	36	Electric swap contracts	**51**	1
Electric option contracts	**-**	1	Electric option contracts	**1**	-
Contracts not subject to rate recovery:			Contracts not subject to rate recovery:		
Gas swap contracts	**-**	-	Gas swap contracts	**1**	-
Hedge contracts:			Hedge contracts:		
CCIRS	**2**	75	CCIRS	**221**	-
	45	140		**332**	43
Other non-current assets:			Other non-current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas swap contracts	**-**	-	Gas swap contracts	**3**	-
Gas future contracts	**-**	-	Gas future contracts	**6**	-
Gas purchase contracts	**22**	18	Gas purchase contracts	**8**	5
Electric swap contracts	**8**	8	Electric swap contracts	**37**	9
Hedge contracts:			Hedge contracts:		
CCIRS	**-**	40	CCIRS	**366**	-
	30	66		**420**	14
Total	**$ 75**	$ 206	Total	**$ 752**	$ 57

The changes in fair value of the Company's rate recoverable contracts are offset by changes in regulatory assets and liabilities. As a result, the changes in fair value of those contracts had no impact in the accompanying consolidated statements of income. The changes in fair value of the Company's contracts not subject to rate recovery are recorded within purchased gas in the accompanying consolidated statements of income.

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price, interest and currency risk management. Credit risk represents the risk of loss due to counterparty non-performance. Credit risk is managed by assessing each counterparty's credit profile and negotiating appropriate levels of collateral and credit support.

Commodity Transactions

The Company enters into commodity transactions on the New York Mercantile Exchange ("NYMEX"). The NYMEX clearinghouses act as the counterparty to each trade. Transactions on the NYMEX must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX are significantly collateralized and have limited counterparty credit risk.

The credit policy for commodity transactions is managed and monitored by the Executive Energy Risk Management Committee ("EERC"), which is responsible for approving risk management policies and objectives for risk assessment, control and valuation, and the monitoring and reporting of risk exposures. The Energy Procurement Risk Management Committee ("EPRMC") is responsible for approving transaction strategies, annual supply plans, and counterparty credit approval, as well as all valuation and control procedures. The EERC is chaired by the Global Tax and Treasury Director and reports to the Finance Committee. The EPRMC is chaired by the Vice President of U.S. Treasury and reports to the EERC.

The EPRMC monitors counterparty credit exposure and appropriate measures are taken to bring such exposures below the limits, including, without limitation, netting agreements, and limitations on the type and tenor of trades. The Company enters into enabling agreements that allow for payment netting with its counterparties, which reduce its exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. In instances where a counterparty's credit quality has declined, or credit exposure exceeds certain levels, the Company may limit its credit exposure by restricting new transactions with the counterparty, requiring additional collateral or credit support, and negotiating the early termination of certain agreements. Similarly, the Company may be required to post collateral to its counterparties.

The Company's credit exposure for all commodity derivative contracts, normal purchase normal sale contracts, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements was a liability of $54 million and an asset of $26 million as of March 31, 2015 and 2014, respectively.

The aggregate fair value of the Company's commodity derivative contracts with credit-risk-related contingent features that are in a liability position at March 31, 2015 and 2014 was $98.3 million and $16.9 million, respectively. The Company had $12.1 million at March 31, 2015 and zero collateral posted for these instruments at March 31, 2014. If the Company's credit rating were to be downgraded by one level, it would be required to post $13.6 million additional collateral to its counterparties at March 31, 2015. If the Company's credit rating were to be downgraded by two levels, it would be required to post $23.6 million additional collateral to its counterparties at March 31, 2015. If the Company's credit rating were to be downgraded by three levels, it would be required to post $96.5 million and $18 million additional collateral to its counterparties at March 31, 2015 and 2014, respectively.

Financing Transactions

The credit policy for financing transactions is managed by a central Treasury department under policies approved by the Finance Committee. In accordance with these treasury policies, counterparty credit exposure utilizations are monitored daily against the counterparty credit limits. Counterparty credit ratings and market conditions are reviewed continually with limits being revised and utilization adjusted, if appropriate. Management does not expect any significant losses from non-performance by these counterparties.

In relation to the Company's cash flow hedge contracts, if the Company's credit rating were to be downgraded by one, two, or three levels, it would not be required to post any additional collateral.

Offsetting Information for Derivatives Subject to Master Netting Arrangements

March 31, 2015
Gross Amounts Not Offset in the Consolidated Balance Sheets
(in millions of dollars)

ASSETS:	Gross amounts of recognized assets *A*	Gross amounts offset in the Consolidated Balance Sheets *B*	Net amounts of assets presented in the Consolidated Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral received *Db*	Net amount *E=C-D*
Derivative contracts						
Gas swap contracts	$ 2	$ -	$ 2	$ -	$ -	$ 2
Gas purchase contracts	40	-	40	-	-	40
Electric swap contracts	31	-	31	-	-	31
CCIRS	2	-	2	-	-	2
Total	$ 75	$ -	$ 75	$ -	$ -	$ 75

LIABILITIES:	Gross amounts of recognized liabilities *A*	Gross amounts offset in the Consolidated Balance Sheets *B*	Net amounts of presented in the Consolidated Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral paid *Db*	Net amount *E=C-D*
Derivative contracts						
Gas swap contracts	$ 41	$ -	$ 41	$ -	$ -	$ 41
Gas future contracts	17	-	17	-	17	-
Gas purchase contracts	18	-	18	-	-	18
Electric swap contracts	88	-	88	-	12	76
Electric option contracts	1	-	1	-	-	1
CCIRS	587	-	587	-	449	138
Total	$ 752	$ -	$ 752	$ -	$ 478	$ 274

March 31, 2014
Gross Amounts Not Offset in the Consolidated Balance Sheets
(in millions of dollars)

ASSETS:	Gross amounts of recognized assets *A*	Gross amounts offset in the Consolidated Balance Sheets *B*	Net amounts of assets presented in the Consolidated Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral received *Db*	Net amount *E=C-D*
Derivative contracts						
Gas swap contracts	$ 12	$ -	$ 12	$ -	$ -	$ 12
Gas future contracts	3	-	3	-	3	-
Gas option contracts	2	-	2	-	-	2
Gas purchase contracts	29	-	29	-	-	29
Electric swap contracts	44	-	44	-	3	41
Electric option contracts	1	-	1	-	-	1
CCIRS	115	-	115	-	25	90
Total	$ 206	$ -	$ 206	$ -	$ 31	$ 175

LIABILITIES:	Gross amounts of recognized liabilities *A*	Gross amounts offset in the Consolidated Balance Sheets *B*	Net amounts of presented in the Consolidated Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral paid *Db*	Net amount *E=C-D*
Derivative contracts						
Gas swap contracts	$ 4	$ -	$ 4	$ -	$ -	$ 4
Gas future contracts	1	-	1	-	1	-
Gas option contracts	1	-	1	-	-	1
Gas purchase contracts	41	-	41	-	-	41
Electric swap contracts	10	-	10	-	-	10
Total	$ 57	$ -	$ 57	$ -	$ 1	$ 56

7. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value in the accompanying consolidated balance sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2015 and 2014:

	March 31, 2015			
	Level 1	Level 2	Level 3	Total
	(in millions of dollars)			
Assets:				
Derivative contracts				
Gas swap contracts	$ -	$ 2	$ -	$ 2
Gas purchase contracts	-	-	40	40
Electric swap contracts	-	31	-	31
CCIRS	-	2	-	2
Available-for-sale securities	125	185	-	310
Total	125	220	40	385
Liabilities:				
Derivative contracts				
Gas swap contracts	-	41	-	41
Gas future contracts	17	-	-	17
Gas purchase contracts	-	-	18	18
Electric swap contracts	-	88	-	88
Electric option contracts	-	-	1	1
CCIRS	-	587	-	587
Total	17	716	19	752
Net assets (liabilities)	$ 108	$ (496)	$ 21	$ (367)

	March 31, 2014			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative contracts				
Gas swap contracts	$ -	$ 12	$ -	$ 12
Gas future contracts	3	-	-	3
Gas option contracts	-	-	2	2
Gas purchase contracts	-	1	28	29
Electric swap contracts	-	44	-	44
Electric option contracts	-	-	1	1
CCIRS	-	115	-	115
Available-for-sale securities	113	124	-	237
Total	116	296	31	443
Liabilities:				
Derivative contracts				
Gas swap contracts	-	4	-	4
Gas future contracts	1	-	-	1
Gas option contracts	-	-	1	1
Gas purchase contracts	-	5	36	41
Electric swap contracts	-	10	-	10
Total	1	19	37	57
Net assets (liabilities)	$ 115	$ 277	$ (6)	$ 386

Derivative Contracts: The Company's Level 1 fair value derivative contracts primarily consist of quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date. Derivative assets and liabilities utilizing Level 1 inputs include active exchange-based derivatives (e.g. natural gas futures traded on NYMEX).

The Company's Level 2 fair value derivative contracts primarily consist of over-the-counter ("OTC") interest and currency swap transactions, and gas swap contracts with pricing inputs obtained from the New York Mercantile Exchange and the Intercontinental Exchange ("ICE"), except in cases where the ICE publishes seasonal averages or where there were no transactions within the last seven days. The Company may utilize discounting based on quoted interest rate curves, including consideration of non-performance risk, and may include a liquidity reserve calculated based on bid/ask spread for the Company's Level 2 derivative contracts. Substantially all of these price curves are observable in the marketplace throughout at least 95% of the remaining contractual quantity, or they could be constructed from market observable curves with correlation coefficients of 95% or higher.

The Company's Level 3 fair value derivative contracts primarily consist of OTC gas option contracts and gas purchase contracts, which are valued based on internally-developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries are used for valuing such instruments. A derivative is designated Level 3 when it is valued based on a forward curve that is internally developed, extrapolated or derived from market observable curves with correlation coefficients less than 95%, where optionality is present, or if non-economic assumptions are made. The internally developed forward curves have a high level of correlation with Platts Mark-to-Market curves and are reviewed by the middle office. The Company considers non-performance risk and liquidity risk in the valuation of derivative contracts categorized in Level 2 and Level 3.

Available-for-Sale Securities: Available-for-sale securities are included in other non-current assets in the accompanying consolidated balance sheets and primarily include equity and debt investments based on quoted market prices (Level 1) and municipal and corporate bonds based on quoted prices of similar traded assets in open markets (Level 2).

Changes in Level 3 Derivative Contracts

	Years Ended March 31,	
	2015	**2014**
	(in millions of dollars)	
Balance as of the beginning of the year	**$ (6)**	$ 11
Transfers out of Level 3	**5**	1
Total gains or losses included in regulatory assets and liabilities	**(17)**	(23)
Settlements	**39**	5
Balance as of the end of the year	**$ 21**	$ (6)
The amount of total gains or losses for the year included in net income attributed to the change in unrealized gains or losses related to non-regulatory assets and liabilities at year-end	**$ -**	$ -

A transfer into Level 3 represents existing assets or liabilities that were previously categorized at a higher level for which the inputs became unobservable during the year. A transfer out of Level 3 represents assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in Level 2. These transfers, which are recognized at the end of each period, result from changes in the observability of forward curves from the beginning to the end of each reporting period. There were no transfers between Level 1 and Level 2, and no transfers into Level 3, during the years ended March 31, 2015 or 2014.

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The forward curves used for financial reporting are developed and verified by the middle office. The Company considers non-performance risk and liquidity risk in the valuation of derivative contracts categorized in Level 2 and Level 3.

Quantitative Information About Level 3 Fair Value Measurements

The following tables provide information about the Company's Level 3 valuations:

Commodity	Level 3 Position	Fair Value as of March 31, 2015			Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)	Total			
		(in millions of dollars)					
Gas	Option contracts	$ -	$ -	$ -	Discounted Cash Flow	Forward Curve Implied Volatility	$0.27-$0.29/dth 34%-41%
Gas	Purchase contracts	35	(18)	17	Discounted Cash Flow	Forward Curve LNG Forward Curve	$0.96-$11.47/dth
Gas	Cross commodity contracts	5	-	5	Discounted Cash Flow	Forward Curve	$17.47-$378.51/dth
Electric	Option contracts	-	(1)	(1)	Discounted Cash Flow	Implied Volatility	30%-69%
	Total	$ 40	$ (19)	$ 21			

Commodity	Level 3 Position	Fair Value as of March 31, 2014			Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)	Total			
		(in millions of dollars)					
Gas	Option contracts	$ 2	$ (1)	$ 1	Discounted Cash Flow	Forward Curve Implied Volatility	$(1.07)-$0.72/dth 29%-31%
Gas	Purchase contracts	25	(36)	(11)	Discounted Cash Flow	Forward Curve LNG Forward Curve	$2.43-$17.31/dth $6.62-$11.01/dth
Gas	Cross commodity contracts	3	-	3	Discounted Cash Flow	Forward Curve	$43.19-$98.98/dth
Electric	Option contracts	1	-	1	Discounted Cash Flow	Implied Volatility	29%-65%
	Total	$ 31	$ (37)	$ (6)			

The significant unobservable inputs listed above would have a direct impact on the fair values of the Level 3 instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of the Company's gas purchase and gas and electric option derivatives are forward commodity prices, both gas and electric, implied volatility and valuation assumptions pertaining to the peaking gas deals based on the forward gas curves. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates.

Other Fair Value Measurements

The Company's consolidated balance sheets reflect long-term debt at amortized cost. The fair value of the Company's long-term debt was based on quoted market prices when available, or estimated using quoted market prices for similar debt. The fair value of this debt at March 31, 2015 and 2014 was $17.2 billion and $17.4 billion, respectively.

All other financial instruments in the accompanying consolidated balance sheets such as accounts receivable and accounts payable are stated at cost, which approximates fair value.

8. EMPLOYEE BENEFITS

The Company sponsors numerous non-contributory defined benefit pension plans (the "Pension Plans") and several PBOP Plans. In general, the Company calculates benefits under these plans based on age, years of service and pay using March 31 as a measurement date. In addition, the Company also sponsors defined contribution plans for eligible employees.

Pension Plans

The Pension Plans are comprised of both qualified and non-qualified plans. The qualified pension plans provide union employees, as well as all non-union employees hired before January 1, 2011, with a retirement benefit. Supplemental, non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives. The Company funds the qualified plans by contributing at least the minimum amount required under Internal Revenue Service ("IRS") regulations. The Company expects to contribute $291 million to the Pension Plans during the year ending March 31, 2016.

PBOP Plans

The PBOP Plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must contribute to the cost of their coverage. The Company funds these plans based on the requirements of the various regulatory jurisdictions in which it operates. The Company expects to contribute $148 million to the PBOP Plans during the year ending March 31, 2016.

Defined Contribution Plans

The Company also has several defined contribution pension plans (primarily 401(k) employee savings fund plans) that cover substantially all employees. In addition, employees may receive certain employer contributions, including matching contributions and a 15% discount on the purchase of National Grid plc common stock. Employer matching contributions of approximately $41 million and $38 million, respectively, were expensed in the years ended March 31, 2015 and 2014.

Components of Net Periodic Benefit Costs

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014
	(in millions of dollars)			
Service cost	**$ 119**	$ 134	**$ 62**	$ 73
Interest cost	**368**	355	**203**	203
Expected return on plan assets	**(473)**	(443)	**(190)**	(170)
Amortization of prior service cost, net	**7**	9	**6**	8
Amortization of net actuarial loss	**237**	252	**61**	83
Settlements/curtailments	**-**	16	**-**	(140)
Total cost	**$ 258**	$ 323	**$ 142**	$ 57

All of the Company's regulated subsidiaries have regulatory recovery of these costs and therefore have recorded related regulatory assets (liabilities) in the accompanying consolidated balance sheets. The Company records amounts for its unregulated subsidiaries within operations and maintenance expense in the accompanying consolidated statements of income.

Amounts Recognized in AOCI and Regulatory Assets

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014
	(in millions of dollars)			
Net actuarial loss (gain) on liabilities	**$ 998**	$ (18)	**$ 501**	$ (319)
Net actuarial (gain) loss on assets	**(205)**	-	**62**	-
Prior service cost (credit)	**2**	-	**-**	(31)
Amortization of net actuarial (loss) gain	**(237)**	(267)	**(61)**	58
Amortization of prior service cost, net	**(7)**	(10)	**(6)**	(9)
Total	**$ 551**	$ (295)	**$ 496**	$ (301)
Included in regulatory assets	**$ 261**	$ (181)	**$ 380**	$ (62)
Included in AOCI	**290**	(114)	**116**	(239)
Total	**$ 551**	$ (295)	**$ 496**	$ (301)

Amounts Recognized in AOCI and Regulatory Assets – not yet recognized as components of net actuarial loss

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014
			(in millions of dollars)	
Net actuarial loss	**$ 2,237**	$ 1,681	**$ 1,146**	$ 644
Prior service cost (credit)	**41**	46	**(29)**	(23)
Total	**$ 2,278**	$ 1,727	**$ 1,117**	$ 621
Included in regulatory assets	**$ 1,147**	$ 886	**$ 777**	$ 397
Included in AOCI	**1,131**	841	**340**	224
Total	**$ 2,278**	$ 1,727	**$ 1,117**	$ 621

The amount of net actuarial loss and prior service cost to be amortized from regulatory assets during the year ended March 31, 2016 for the Pension Plans and PBOP Plans is $419 million and $2 million, respectively.

Reconciliation of Funded Status to Amount Recognized

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014
		(in millions of dollars)		
Change in benefit obligation:				
Benefit obligation as of the beginning of the year	**$ (7,872)**	$ (7,724)	**$ (4,469)**	$ (4,589)
Service cost	**(119)**	(134)	**(62)**	(73)
Interest cost on projected benefit obligation	**(368)**	(355)	**(203)**	(203)
Plan amendments	**(2)**	-	**-**	31
Net actuarial loss	**(998)**	(157)	**(501)**	(103)
Benefits paid	**425**	357	**197**	190
Settlements/curtailments	**-**	141	**-**	304
Other	**-**	-	**(29)**	(26)
Benefit obligation as of the end of the year	**(8,934)**	(7,872)	**(5,067)**	(4,469)
Change in plan assets:				
Fair value of plan assets as of the beginning of the year	**7,052**	6,654	**2,702**	2,302
Actual return on plan assets	**678**	591	**128**	287
Company contributions	**197**	279	**194**	303
Benefits paid	**(425)**	(357)	**(197)**	(190)
Settlements	**-**	(115)	**-**	-
Fair value of plan assets as of the end of the year	**7,502**	7,052	**2,827**	2,702
Funded status	**$ (1,432)**	$ (820)	**$ (2,240)**	$ (1,767)

The benefit obligation shown above is the projected benefit obligation ("PBO") for the Pension Plans and the accumulated benefit obligation ("ABO") for the PBOP Plans. The Company is required to reflect the funded status of its Pension Plans above in terms of the PBO, which is higher than the ABO, because the PBO includes the impact of expected future compensation increases on the pension obligation. The Pension Plans had ABO balances that exceeded the fair value of plans assets as of March 31, 2015 and 2014. The aggregate ABO balances for the Pension Plans were $8.5 billion and $7.4 billion as of March 31, 2015 and 2014, respectively.

Amounts Recognized in the Accompanying Consolidated Balance Sheets

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2015	2014	**2015**	2014
	(in millions of dollars)			
Non-current assets	**$ 179**	$ 290	**$ 10**	$ 15
Current liabilities	**(23)**	(22)	**(16)**	(16)
Non-current liabilities	**(1,588)**	(1,088)	**(2,234)**	(1,766)
Total	**$ (1,432)**	$ (820)	**$ (2,240)**	$ (1,767)

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2015:

(in millions of dollars) Years Ending March 31,	Pension Plans	PBOP Plans
2016	$ 493	$ 197
2017	505	204
2018	513	211
2019	517	217
2020	521	223
Thereafter	2,683	1,199
Total	$ 5,232	$ 2,251

Assumptions Used for Employee Benefits Accounting

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014
Benefit Obligations:				
Discount rate	**4.10%**	4.80%	**4.10%**	4.80%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50%
Expected return on plan assets	**6.25%**	7.00%	**6.25% - 6.75%**	7.00% - 7.25%
Net Periodic Benefit Costs:				
Discount rate	**4.80%**	4.70%	**4.80%**	4.70%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50%
Expected return on plan assets	**7.00%**	6.75% - 7.25%	**7.00%-7.25%**	7.25%-7.50%

The Company selects its discount rate assumption based upon rates of return on highly rated corporate bond yields in the marketplace as of each measurement date. Specifically, the Company uses the Hewitt AA Above Median Curve along with the expected future cash flows from the Company retirement plans to determine the weighted average discount rate assumption.

Mortality assumptions are used to estimate life expectancies of plan participants and the expected period over which they will receive pension benefits. The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population and an improvement scale that anticipates future improvements in life expectancy. In October 2014, the Society of Actuaries ("SOA") issued updated mortality tables (RP-2014) and a mortality improvement scale (MP-2014), which reflect longer life expectancies than previously projected.

The Company's pension and PBOP obligations as of March 31, 2015 reflect a change in the underlying mortality assumption consistent with the SOA study. These changes resulted in an increase in the projected benefit obligation of $390 million as of March 31, 2015.

The expected rate of return for various passive asset classes is based both on analysis of historical rates of return and forward looking analysis of risk premiums and yields. Current market conditions, such as inflation and interest rates, are evaluated in connection with the setting of the long-term assumptions. A small premium is added for active management of both equity and fixed income securities. The rates of return for each asset class are then weighted in accordance with the actual asset allocation, resulting in a long-term return on asset rate for each plan.

Assumed Health Cost Trend Rate

	March 31,	
	2015	2014
Health care cost trend rate assumed for next year		
Pre 65	**8.00%**	8.00%
Post 65	**6.50%**	7.00%
Prescription	**6.50%**	7.00%
Rate to which the cost trend is assumed to decline (ultimate)	**5.00%**	5.00%
Year that rate reaches ultimate trend		
Pre 65	**2022**	2022
Post 65	**2022**	2021
Prescription	**2022**	2021

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

(in millions of dollars)	**March 31, 2015**
1% point increase	
Total of service cost plus interest cost	$ 48
Postretirement benefit obligation	750
1% point decrease	
Total of service cost plus interest cost	(39)
Postretirement benefit obligation	(631)

Plan Assets

The Company manages the benefit plan investments to minimize the long-term cost of operating the plans, with a reasonable level of risk. Risk tolerance is determined as a result of a periodic asset/liability study which analyzes the plans' liabilities and funded status and results in the determination of the allocation of assets across equity and fixed income securities. Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across market segments. Small investments are also approved for private equity, real estate, and infrastructure with the objective of enhancing long-term returns while improving portfolio diversification. For the PBOP Plans, since the earnings on a portion of the assets are taxable, those investments are managed to maximize after tax returns consistent with the broad asset class parameters established by the asset allocation study. Investment risk and return are reviewed by the Company's investment committee on a quarterly basis.

The target asset allocations for the benefit plans as of March 31, 2015 and 2014 are as follows:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2015	2014	**2015**	2014
U.S. equities	**20%**	20%	**39%**	39%
Global equities (including U.S.)	**7%**	7%	**6%**	6%
Global tactical asset allocation	**10%**	10%	**9%**	9%
Non-U.S. equities	**10%**	10%	**21%**	21%
Fixed income	**40%**	40%	**25%**	25%
Private equity	**5%**	5%	**0%**	0%
Real estate	**5%**	5%	**0%**	0%
Infrastructure	**3%**	3%	**0%**	0%
	100%	100%	**100%**	100%

Fair Value Measurements

The following tables provide the fair value measurements amounts for the pension and PBOP assets.

	March 31, 2015			
	Level 1	**Level 2**	**Level 3**	**Total**
		(in millions of dollars)		
Pension Assets:				
Cash and cash equivalents	$ 19	$ 107	$ -	$ 126
Accounts receivable	138	-	-	138
Accounts payable	(139)	-	-	(139)
Equity	887	1,907	315	3,109
Global tactical asset allocation	-	-	323	323
Fixed income securities	-	3,000	128	3,128
Preferred securities	1	29	-	30
Futures contracts	-	4	-	4
Private equity	-	-	413	413
Real estate	-	77	293	370
Total	$ 906	$ 5,124	$ 1,472	$ 7,502
PBOP Assets:				
Cash and cash equivalents	$ 39	$ 10	$ -	$ 49
Accounts receivable	5	-	-	5
Accounts payable	(1)	-	-	(1)
Equity	428	1,336	116	1,880
Global tactical asset allocation	69	-	132	201
Fixed income securities	2	684	-	686
Private equity	-	-	7	7
Total	$ 542	$ 2,030	$ 255	$ 2,827

	March 31, 2014							
	Level 1		Level 2		Level 3		Total	
				(in millions of dollars)				
Pension Assets:								
Cash and cash equivalents	$	5	$	116	$	1	$	122
Accounts receivable		93		-		-		93
Accounts payable		(82)		-		-		(82)
Equity		846		1,796		318		2,960
Global tactical asset allocation		-		244		54		298
Fixed income securities		-		2,890		46		2,936
Preferred securities		2		-		-		2
Futures contracts		4		-		-		4
Private equity		-		-		409		409
Real estate		-		-		310		310
Total	$	868	$	5,046	$	1,138	$	7,052
PBOP Assets:								
Cash and cash equivalents	$	49	$	17	$	-	$	66
Accounts receivable		6		-		-		6
Accounts payable		(5)		-		-		(5)
Equity		460		1,219		105		1,784
Global tactical asset allocation		72		98		24		194
Fixed income securities		2		647		-		649
Private equity		-		-		8		8
Total	$	584	$	1,981	$	137	$	2,702

The methods used to fair value pension and PBOP assets are described below:

Cash and Cash Equivalents: Cash and cash equivalents that can be priced daily are classified as Level 1. Active reserve funds, reserve deposits, commercial paper, repurchase agreements, and commingled cash equivalents are classified as Level 2. Such instruments are generally valued using a curve methodology that includes observable inputs such as money market rates for specific instruments, programs, currencies and maturity points obtained from a variety of market makers, reflective of current trading levels. The methodologies consider an instrument's days to final maturity to generate a yield based on the relevant curve for the instrument.

Accounts Receivable and Accounts Payable: Accounts receivable and accounts payable are classified in the same category as the investments to which they relate. Such amounts are short-term and settle within a few days of the measurement date.

Equity and Preferred Securities: Common stocks, preferred stocks, and real estate investment trusts are valued using the official close of the primary market on which the individual securities are traded. Equity securities are primarily comprised of securities issued by public companies in domestic and foreign markets plus investments in commingled funds, which are valued on a daily basis. The Company can exchange shares of the publicly traded securities and the fair values are primarily sourced from the closing prices on stock exchanges where there is active trading, in which case they are classified as Level 1 investments. If there is less active trading, then the publicly traded securities would typically be priced using observable data, such as bid and ask prices, and these measurements are classified as Level 2 investments. Investments that are not publicly traded and valued using unobservable inputs are classified as Level 3 investments. Commingled funds with publicly quoted prices and active trading are classified as Level 1 investments. For investments in commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the net asset value ("NAV") per fund share, derived from the underlying securities' quoted prices in active markets, and they are classified as Level 2 investments. Investments in commingled funds with redemption restrictions and that use NAV are classified as Level 3 investments.

Global Tactical Asset Allocation: Assets held in global tactical asset allocation funds are managed by investment managers who use both top-down and bottom-up valuation methodologies to value asset classes, countries, industrial sectors, and individual securities in order to allocate and invest assets opportunistically. If the inputs used to measure a financial instrument fall within different levels of the fair value hierarchy within the commingled fund, the categorization is based on the lowest level input that is significant to the measurement of that financial instrument. The assets invested through commingled funds are classified as Level 2. Those which are open ended mutual funds with observable pricing are classified as Level 1. However, the underlying Level 3 assets that makeup these funds are classified in the same category as the investments to which they relate.

Fixed Income Securities: Fixed income securities (which include corporate debt securities, municipal fixed income securities, U.S. Government and Government agency securities including government mortgage backed securities, index linked government bonds, and state and local bonds) convertible securities, and investments in securities lending collateral (which include repurchase agreements, asset backed securities, floating rate notes and time deposits) are valued with an institutional bid valuation. A bid valuation is an estimated price at which a dealer would pay for a security (typically in an institutional round lot). Oftentimes, these evaluations are based on proprietary models which pricing vendors establish for these purposes. In some cases there may be manual sources when primary vendors do not supply prices. Fixed income investments are primarily comprised of fixed income securities and fixed income commingled funds. The prices for direct investments in fixed income securities are generated on a daily basis. Prices generated from less active trading with wider bid ask prices are classified as Level 2 investments. If prices are based on uncorroborated and unobservable inputs, then the investments are classified as Level 3 investments. Commingled funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, derived from the underlying securities' quoted prices in active markets, and are classified as Level 2 investments. Investments in commingled funds with redemption restrictions and that use NAV are classified as Level 3.

Private Equity and Real Estate: Commingled equity funds, commingled special equity funds, limited partnerships, real estate, venture capital and other investments are valued using evaluations (NAV per fund share), based on proprietary models, or based on the NAV. Investments in private equity and real estate funds are primarily invested in privately held real estate investment properties, trusts, and partnerships as well as equity and debt issued by public or private companies. The Company's interest in the fund or partnership is estimated based on the NAV. The Company's interest in these funds cannot be readily redeemed due to the inherent lack of liquidity and the primarily long-term nature of the underlying assets. Distribution is made through the liquidation of the underlying assets. The Company views these investments as part of a long-term investment strategy. These investments are valued by each investment manager based on the underlying assets. The funds utilize valuation techniques consistent with the market, income, and cost approaches to measure the fair value of certain real estate investments. The majority of the underlying assets are valued using significant unobservable inputs and often require significant management judgment or estimation based on the best available information. Market data includes observations of the trading multiples of public companies considered comparable to the private companies being valued. As a result, the Company classifies these investments as Level 3.

While management believes its valuation methodologies are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of Level 3 financial instruments could result in a different fair value measurement at the reporting date.

Changes in Level 3 Plan Investments

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014
	(in millions of dollars)			
Balance as of the beginning of the year	**$ 1,138**	$ 801	**$ 137**	$ 56
Transfers out of Level 3	**(444)**	(16)	**(32)**	(41)
Transfers into Level 3	**457**	282	**50**	102
Actual gain or loss on plan assets:				
Realized gain	**85**	37	**9**	3
Unrealized gain (loss)	**84**	56	**17**	(1)
Purchases	**506**	397	**101**	37
Sales	**(354)**	(419)	**(27)**	(19)
Balance as of the end of the year	**$ 1,472**	$ 1,138	**$ 255**	$ 137

Other Benefits

At March 31, 2015 and 2014, the Company had accrued workers compensation, auto, and general insurance claims which have been incurred but not yet reported of $82.7 million and $83.7 million, respectively.

9. ACCUMULATED OTHER COMPREHENSIVE INCOME

The following table represents the changes in the Company's AOCI for the year ended March 31, 2015:

	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Foreign Currency Translation	Total
		(in millions of dollars)			
Balance as of the beginning of the year	$ 2	$ (652)	$ 2	$ (139)	$ (787)
Other comprehensive income (loss) before reclassifications:					
Unrecognized net acturial loss (net of $0, $219, $0, and $0 tax benefit, respectively)	-	(313)	-	-	(313)
Gain on investment (net of $9, $0, $0, and $0 tax expense, respectively)	13	-	-	-	13
Amounts reclassified from other comprehensive income (loss):					
Amortization of net actuarial loss (net of $0, $52,$0, and $0 tax expense, respectively)	-	75	-	-	75
Amortization of treasury lock (net of $0, $0, $3, and $0 tax expense, respectively) (1)	-	-	6	-	6
Gain on investment (net of $5, $0, $0, and $0 tax benefit, respectively) (2)	(7)	-	-	-	(7)
Net current period other comprehensive income (loss)	6	(238)	6	-	(226)
Balance as of the end of the year	$ 8	$ (890)	$ 8	$ (139)	$ (1,013)

(1) Amounts are reported in interest on long-term debt in the accompanying consolidated statements of income.

(2) Amounts are reported as other deductions, net in the accompanying consolidated statements of income.

10. CAPITALIZATION

European Medium Term Note Program

At March 31, 2015, the Company had a Euro Medium Term Note program (the "Program") under which it is able to issue debt instruments ("Instruments") up to a total of the equivalent of 4 billion Euros. Instruments issued under the Program are admitted to trading on the London Stock Exchange. The Program commenced in December 2007 and is renewed annually, with the latest renewal of the Program expiring in December 2015. If the Program is not renewed in December 2015, it would preclude the issuance of new notes under this Program, but it would not impact the outstanding debt balances and their maturity dates. Instruments carry certain affirmative and negative covenants, including a restriction on the Company's ability to mortgage, pledge, charge or otherwise encumber its assets in order to secure, guarantee or indemnify other listed or quoted debt obligations, as well as cross-acceleration in the event of breach by the Company or its principal subsidiaries of other listed or quoted debt obligations. At March 31, 2015 and 2014, the Company was in compliance with all covenants. At March 31, 2015 and 2014, $3.4 billion and $2.5 billion, respectively, of these notes were issued and outstanding, excluding the impact of interest rate and currency swaps.

Notes Payable

At March 31, 2015 and 2014 the Company had outstanding $6.3 billion and $6.8 billion, respectively, of unsecured medium and long-term notes. In September 2014, Niagara Mohawk issued $500 million of unsecured long-term debt at 3.508% with a maturity date of October 1, 2024 and $400 million of unsecured long-term debt at 4.278% with a maturity date of October 1, 2034. The interest rates on the unsecured notes range from 2.721% to 9.750% and maturity dates range from October 2015 through December 2042. In June 2013, the Company entered into a new bank loan for $762.6 million. This 18-month loan contained an option to extend for a further year. The loan was originally borrowed in sterling, but swapped to USD at a fixed rate of 1.1325%. On June 30, 2014 the Company repaid the $762.6 million bank loan.

On August 9, 2011, the Company entered into two loan agreements with Bank of Tokyo-Mitsubishi UFJ, Ltd. for $250 million with an interest rate of London Interbank Offered Rate ("LIBOR") plus a margin spread of 0.7%, which matured in August 2013 and $500 million with an interest rate of LIBOR plus a margin spread of 0.9%, which was scheduled to mature on October 29, 2014 and was paid in advance in February 2014. On August 19, 2011, the Company entered into a term loan agreement with the Mizuho Corporate Bank, Ltd. for $250 million with an interest rate of LIBOR plus a margin spread of 0.7%, which matured in August 2013.

Gas Facilities Revenue Bonds

Brooklyn Union has outstanding tax-exempt Gas Facilities Revenue Bonds ("GFRB") issued through the New York State Energy Research and Development Authority ("NYSERDA"). There are no sinking fund requirements for any of Brooklyn Union's GFRB. At March 31, 2015 and 2014, $641 million of GFRB were outstanding; $230 million of which are variable-rate, auction rate bonds. The interest rate on the various variable rate series due starting December 1, 2020 through July 1, 2026 is reset weekly and ranged from 0.07% to 0.44% during the year ended March 31, 2015 and 0.07% to 0.51% during the year ended March 31, 2014. The GFRB are currently in auction rate mode and are backed by bond insurance. These bonds cannot be put back to Brooklyn Union and, in the case of a failed auction, the resulting interest rate on the bonds would revert to the maximum rate which depends on the current appropriate, short-term benchmark rates and the senior unsecured rating of the Brooklyn Union's bonds. The effect of the failed auctions on interest expense was not material for the years ended March 31, 2015 or 2014.

Promissory Notes to LIPA

KeySpan Corporation had previously issued $155 million of promissory notes to LIPA to support certain debt obligations assumed by LIPA. Following the expiration of the MSA on December 31, 2013, the debt was fully extinguished (refer to Note 18, "Discontinued Operations").

First Mortgage Bonds

The assets of Colonial Gas and Narragansett are subject to liens and other charges and are provided as collateral over borrowings of $75 million and $50 million, respectively, of non-callable First Mortgage Bonds ("FMB"). These FMB indentures include, among other provisions, limitations on the issuance of long-term debt. Interest rates range from 6.82% to 9.63% and maturity dates range from April 2018 to April 2028.

State Authority Financing Bonds

At March 31, 2015, the Company had outstanding $1 billion of State Authority Financing Bonds. Of the $1 billion outstanding at March 31, 2015, approximately $571 million of these bonds were issued through NYSERDA and the remaining $462 million were issued through various other state agencies.

Approximately $605 million of State Authority Financing Bonds were issued to secure a like amount of tax-exempt revenue bonds issued by NYSERDA. Approximately $430 million of such securities bear interest at short-term adjustable interest rates (with an option to convert to other rates, including a fixed interest rate) ranging from 0.37% to 0.45% for the year ended March 31, 2015. The bonds are currently in auction rate mode and are backed by bond insurance. These bonds cannot be put back to the Company and, in the case of a failed auction, the resulting interest rate on the bonds would revert to the maximum rate which depends on the current appropriate, short-term benchmark rate and the senior secured rating of the Company or the bond insurer, whichever is greater. The effect on interest expense has not been material in either of the years ended March 31, 2015 or 2014.

The Company also has $75 million of 5.15% fixed rate pollution control revenue bonds issued through NYSERDA which are callable at par. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generation facilities (which the Company subsequently sold) or to refund outstanding tax-exempt bonds and notes.

Additionally, the Company has $41 million of 1999 Series A Pollution Control Revenue Bonds due October 1, 2028. The interest rate ranged from 0.10% to 1.44% for the year ended March 31, 2015, at which time the rate was 0.90%. The interest rate ranged from 0.15% to 1.35% for the year ended March 31, 2014, at which time the rate was 0.61%. Interest expense related to these notes for each of the years ended March 31, 2015 and 2014 was approximately $0.4 million.

The Company also has outstanding $25 million variable rate 1997 Series A Electric Facilities Revenue Bonds due December 1, 2027. The interest rate on these bonds is reset weekly and ranged from 0.13% to 0.28% and from 0.04% to 0.25% during the years ended March 31, 2015 and 2014, respectively. The interest rate was 0.13% and 0.25% at March 31, 2015 and 2014, respectively. Interest expense related to these notes for each of the years ended March 31, 2015 and 2014 was approximately $0.1 million.

At March 31, 2015, the Company had outstanding $410 million of the Pollution Control Revenue Bonds in tax exempt commercial paper mode with maturity dates ranging from October 2015 to October 2022 and variable interest ranging from 0.07% to 0.46% for the year ended March 31, 2015. In addition, at March 31, 2015, the Company had $52 million of tax exempt Electric Revenue Bonds in commercial paper mode with varying maturity dates from March 2016 through August 2042 and variable interest rates ranging from 0.06% to 0.38% during the year ended March 31, 2015. The bonds were issued by the Massachusetts Development Finance Agency in connection with the Company's financing of its first and second underground and submarine cable projects. Sinking fund payments of $0.3 million were made during the year ended March 31, 2015.

At March 31, 2012, three of the Company's subsidiaries had a Standby Bond Purchase Agreement ("SBPA") totaling $500 million, which expires on November 20, 2015. In November 2014, the SBPA agreement was renewed and is due to expire on November 20, 2019. This agreement was available to provide liquidity support for $463 million of the Company's long-term bonds in tax-exempt commercial paper mode. The Company has classified this debt as long-term due to its intent and ability to refinance the debt on a long-term basis in the event of a failure to remarket the bonds. The Company, together with other affiliates of the Parent, has rights to issue debt under an $850 million syndicated revolving credit facility which can be drawn upon at any time until its maturity in November 2015 and may be used, if needed, to refinance the tax-exempt commercial paper on a long-term basis. This facility has a number of financial and non-financial covenants which the Company is obliged to meet. At March 31, 2015 and 2014, the Company was in compliance with all covenants.

Industrial Development Revenue Bonds

At March 31, 2015 and 2014, Genco had outstanding $128 million of 5.25% tax-exempt bonds due June 1, 2027. Of this amount, $53 million was issued through the Nassau County Industrial Development Authority for the construction of the Glenwood electric-generation peaking plant and the balance of $75 million was issued by the Suffolk County Industrial Development Authority for the Port Jefferson electric-generation peaking plant. KeySpan Corporation has fully and unconditionally guaranteed the payment obligations with regard to these tax-exempt bonds.

Committed Facility Agreements

At March 31, 2015, NGUSA, NGNA, and the Parent have a committed revolving credit facility of $850 million which matures in November 2015. This facility has not been drawn against. NGUSA, NGNA, and the Parent can all draw on this facility in a variety of currencies as needed, but the aggregate borrowings across the group cannot exceed the $850 million limit. The terms of the facility restrict the borrowing of all U.S. subsidiaries of the Company to $18 billion excluding intercompany indebtedness. Additionally, this facility has a number of non-financial covenants which the Company is obliged to meet. At March 31, 2015 and 2014, NGNA and the Parent were in compliance with all covenants.

NGUSA and the Parent have two additional committed revolving credit facilities of $280 million and £155 million which mature in July 2017. These facilities have not been drawn against. NGUSA and the Parent can draw on these facilities in a variety of currencies as needed, but the aggregate borrowings across the group cannot exceed the $280 million and £155 million limit, respectively. The terms of the facilities restrict the borrowing of all U.S. subsidiaries of the Company to $18 billion excluding intercompany indebtedness. Additionally, these facilities have a number of non-financial covenants which NGNA and the Parent were obliged to meet. At March 31, 2015 and 2014, the Company was in compliance with all covenants.

On May 29, 2015, new facilities totaling £1.7 billion were signed, replacing the committed facilities of $850 million and $280 million and part of the £155 million facility. The £155 million facility was reduced to £30 million.

Intercompany Notes Payable

NGNA's intercompany debt is in the form of intercompany loans from the Parent and other affiliated entities obtained to fund the acquisition of various entities. The intercompany loans are paid back by NGNA from the dividends it receives from NGUSA. A summary of the Intercompany Notes Payable is as follows:

			March 31,	
Due to:	**Interest Rate**	**Maturity Date**	**2015**	2014
			(in millions of dollars)	
National Grid Lux Investments Limited	0.78% to 2.2% over LIBOR	August 2015 - August 2027	**$ 2,672**	$ 3,022
National Grid U.S. Partner 1 Limited	1.51% to 1.56% over LIBOR	August 2015 - August 2016	**100**	200
National Grid Twenty Five Limited	2.00% to 2.3% over LIBOR	August 2016 - August 2018	**1,366**	1,681
Total			**$ 4,138**	$ 4,903

Debt Maturities

The aggregate maturities of long-term debt for the years subsequent to March 31, 2015 are as follows:

(in millions of dollars) Years Ending March 31,		
2016	$	1,658
2017		1,675
2018		1,900
2019		684
2020		1,284
Thereafter		8,649
Total	$	15,850

The Company is obligated to meet certain financial and non-financial covenants. The Company's subsidiaries also have restrictions on the payment of dividends which relate to their debt to equity ratios. During the years ended March 31, 2015 and 2014, the Company was in compliance with all such covenants and restrictions.

Some of the Company's State Authority Financing Bonds, First Mortgage Bonds, and Notes Payable have sinking fund requirements which totaled $1 million and $7 million during the years ended March 31, 2015 and 2014, respectively. The following table reflects the sinking fund repayment requirements for the years subsequent to March 31, 2015:

(in millions of dollars) Years Ending March 31,		
2016	$	2
2017		1
2018		1
2019		1
2020		1
Thereafter		8
Total	$	14

Commercial Paper and Revolving Credit Agreements

At March 31, 2015, the Company had two commercial paper programs totaling $4 billion; a $2 billion U.S. commercial paper program and a $2 billion Euro commercial paper program. In support of these programs, the Company was a named borrower under National Grid plc credit facilities with $1.4 billion available to the Company. These facilities support both the Parent's and the Company's commercial paper programs for ongoing working capital needs. The facilities expire in 2015 to 2017. At March 31, 2015 and 2014, there were $486 million and $421 million of borrowings outstanding on the U.S. commercial paper program and $96 million outstanding on the Euro commercial paper program.

The credit facilities allow both the Parent and the Company to borrow in multi-currencies. The current annual commitment fees range from 0.20% to 0.21%. If for any reason the Company were not able to issue sufficient commercial paper or source funds from other sources, the facilities could be drawn upon to meet cash requirements. The facilities contain certain affirmative and negative operating covenants, including restrictions on the Company's utility subsidiaries' ability to mortgage, pledge, encumber or otherwise subject their utility property to any lien, as well as financial covenants that require the Company and the Parent to limit the total indebtedness in U.S. and non-U.S. subsidiaries to pre-defined limits. Violation of these covenants could result in the termination of the facilities and the required repayment of amounts borrowed thereunder, as well as possible cross defaults under other debt agreements. At March 31, 2015 and 2014, the Company was in compliance with all covenants.

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ (54)**	$ (88)
State	**36**	25
Total current tax (benefit) expense	**(18)**	(63)
Deferred tax expense:		
Federal	**194**	204
State	**17**	42
Total deferred tax expense	**211**	246
Amortized investment tax credits [1]	**(5)**	(5)
Total deferred tax expense	**206**	241
Total income tax expense	**$ 188**	$ 178

[1] Investment tax credits ("ITC") are being deferred and amortized over the depreciable life of the property giving rise to the credits.

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2015 and 2014 are 36.2% and 27.9%, respectively. The following table presents a reconciliation of income tax expense at the federal statutory tax rate of 35% to the actual tax expense:

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Computed tax	**$ 182**	$ 223
Change in computed taxes resulting from:		
Audit and related reserve movements	**(10)**	(70)
Investment tax credits	**(5)**	(5)
State income tax, net of federal benefit	**35**	44
Other items, net	**(14)**	(14)
Total	**6**	(45)
Federal and state income taxes	**$ 188**	$ 178

The Company files a consolidated federal income tax return with its subsidiaries. The Company has joint and several liability for any potential assessments against the consolidated group. The Company also files unitary, combined, and separate state income tax returns.

In September 2013, the U.S. Department of the Treasury issued final tangible property regulations which provide guidance for the application of IRC §162(a) and IRC §263(a) to amounts paid to acquire, produce, or improve tangible property. In August 2014, the U.S. Department of the Treasury also finalized the depreciable property disposition regulations. Both sets of regulations become effective for tax years beginning on or after January 1, 2014, which, for the Company, is the fiscal year ended March 31, 2015. The Company intends to adopt these regulations with its fiscal year 2015 federal tax return and has estimated a favorable §481(a) adjustment of $122 million related to dispositions of depreciable property and an unfavorable §481(a) adjustment of $74 million related to repairs deduction following casualty loss.

On July 24, 2013, the Massachusetts legislature enacted into law transportation finance legislation which included significant tax changes affecting the classification of utility corporations. For tax years beginning on or after January 1, 2014, Massachusetts utility corporations will be taxed in the same manner as general business corporations. The state income tax rate increased from 6.5% to 8%. Also, any unitary net operating loss generated post-2013 and allocated to the utilities will be allowed as a carryforward tax attribute. As of March 31, 2014, all Massachusetts state deferred tax balances at the regulated utilities were remeasured to the 8% rate, resulting in an increase in deferred tax liabilities of $47 million with an offset to the regulatory deferred tax asset.

On March 31, 2014, New York's legislature enacted, as part of the 2014-15 budget package, legislation which included significant tax changes. For tax years beginning on or after January 1, 2016, the New York corporate franchise rate is reduced from 7.1% to 6.5%. Additionally, for tax years beginning on or after January 1, 2015, New York state will generally require combined reporting if the taxpayer is engaged in a unitary business and a 50% common ownership test is met. As of March 31, 2014, the Company remeasured its New York state deferred tax assets and liabilities based upon the enacted law that will apply when the corresponding state temporary differences are expected to be realized or settled. Specifically to reflect the decrease in tax rate, the Company decreased its New York state deferred tax liability by $24.5 million with an offset of $27.6 million to regulatory liabilities and $3.1 million to income tax expense. During the year ended March 31, 2015, the Company updated the impact of the tax rate change and adjusted its New York state deferred tax liability by $2.7 million with an offset of $0.9 million to regulatory liabilities and $3.6 million to income tax expense.

Deferred Tax Components

	March 31,	
	2015	2014
	(in millions of dollars)	
Deferred tax assets:		
Environmental remediation costs	**$ 587**	$ 563
Future federal benefit on state taxes	**188**	179
Net operating losses	**588**	288
Postretirement benefits and other employee benefits	**1,738**	1,514
Regulatory liabilities - other	**530**	326
Other items	**415**	232
Total deferred tax assets [1]	**4,046**	3,102
Deferred tax liabilities:		
Property related differences	**6,208**	5,615
Regulatory assets - environmental response costs	**712**	681
Regulatory assets - postretirement benefits	**729**	722
Regulatory assets - other	**648**	432
Other items	**300**	223
Total deferred tax liabilities	**8,597**	7,673
Net deferred income tax liabilities	**4,551**	4,571
Deferred investment tax credits	**35**	37
Net deferred income tax liabilities and investment tax credits	**4,586**	4,608
Current portion of deferred income tax assets, net	**(266)**	(137)
Deferred income tax liabilities, net	**$ 4,852**	$ 4,745

[1] There were no valuation allowances for deferred tax assets at March 31, 2015 or 2014.

The following table presents the amounts and expiration dates of net operating losses as of March 31, 2015:

Expiration of net operating losses:	Federal	State of Massachusetts
	(in millions of dollars)	
3/31/2029	$ 431	$ -
3/31/2030	129	-
3/31/2032	156	-
3/31/2033	583	2
3/31/2034	669	3
3/31/2035	513	89

Expiration of state and city net operating losses:	State of New York	City of New York
	(in millions of dollars)	
3/31/2035	$ 1,185	$ 282

Unrecognized Tax Benefits

As of March 31, 2015 and 2014, the Company's unrecognized tax benefits totaled $817 million and $789 million, respectively, of which $183 million and $180 million, respectively, would affect the effective tax rate, if recognized. The unrecognized tax benefits are included in other non-current liabilities in the accompanying consolidated balance sheets.

The following table presents changes to the Company's unrecognized tax benefits:

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 789**	$ 1,055
Gross increases - tax positions in prior periods	**19**	53
Gross decreases - tax positions in prior periods	**(45)**	(152)
Gross increases - current period tax positions	**59**	68
Settlements with tax authorities	**(5)**	(235)
Balance as of the end of the year	**$ 817**	$ 789

As of March 31, 2015 and 2014, the Company has accrued for interest related to unrecognized tax benefits of $52 million and $67 million, respectively. During the years ended March 31, 2015 and 2014, the Company recorded interest expense of $4 million and $15 million, respectively. The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other deductions, net, in the accompanying consolidated statements of income. No tax penalties were recognized during the years ended March 31, 2015 or 2014.

It is reasonably possible that other events will occur during the next twelve months that would cause the total amount of unrecognized tax benefits to increase or decrease. However, the Company does not believe any such increases or decreases would be material to its results of operations, financial position, or cash flows.

During the year ended March 31, 2014, the IRS concluded its examination of the NGNA consolidated filing group's corporate income tax returns, which includes corporate income tax returns of KeySpan Corporation and subsidiaries for the short period ended August 24, 2007, and of NGNA and subsidiaries for the periods ended March 31, 2008 and 2009. These examinations were completed on March 27, 2014 and March 31, 2014, respectively, with an agreement on the majority of income tax issues for the years referenced above, as well as an acknowledgment that certain discrete items remain disputed. NGNA is in the process of appealing these disputed issues with the IRS Office of Appeals. The Company does not anticipate a change in its unrecognized tax positions in the next twelve months as a result of the appeals. However, pursuant to the Company’s tax sharing agreement, the audit or appeals may result in a change to allocated tax. The tax returns for the years ended March 31, 2010 through March 31, 2015 remain subject to examination by the IRS.

The Company is a member of the NGUSA Service Company Massachusetts unitary group since the fiscal year ended March 31, 2010. The tax returns for the fiscal years ended March 31, 2010 through March 31, 2015 remain subject to examination by the state of Massachusetts.

The Company is in the process of appealing certain adjustments made by the Massachusetts Department of Revenue ("MADOR") for the years ended March 31, 2001 through March 31, 2005. The Company is currently under audit by the MADOR for the years ended March 31, 2006 through March 31, 2008.

The state of New York is in the process of examining the Company's New York state income tax returns for KeySpan Gas East for the period January 1, 2003 through March 31, 2008 and for Brooklyn Union for the period January 1, 2007 through March 31, 2008. The tax returns for the years ended March 31, 2009 through March 31, 2015 remain subject to examination by the state of New York.

New York state and New York City are in the process of an examining the returns of KeySpan Corporation and subsidiaries for the period January 1, 2003 through March 31, 2008 and January 1, 2003 through December 31, 2005, respectively.

During the year ended March 31, 2015, the state of New York concluded its examination of the Niagara Mohawk Holdings Inc. and subsidiaries combined returns for the years ended March 31, 2006 through March 31, 2008. The examination did not result in adjustments to the Company's taxable income. The tax returns for the years ended March 31, 2009 through March 31, 2015 remain subject to examination by the state of New York.

The following table indicates the earliest tax year subject to examination for each major jurisdiction:

Jurisdiction	**Tax Year**
Federal	August 24, 2007 *
Massachusetts	March 31, 2001 *
New York	December 31, 2003
New York City	December 31, 2003
New Hampshire	March 31, 2009

*The Company is in the process of appealing certain disputed issues with the IRS Office of Appeals for the short period ended August 24, 2007 and the years ended March 31, 2008 through March 31, 2009. The Company is also in the process of appealing certain disputed issues with the MADOR for the years ended March 31, 2001 through March 31, 2005.

12. GOODWILL

The following table represents the changes in the carrying amount of goodwill for the years ended March 31, 2015 and 2014:

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 7,151**	$ 7,151
Impairment in Clean Line	**(22)**	-
Balance as of the end of the year	**$ 7,129**	$ 7,151

In January 2013, the Company made an investment in Clean Line. Clean Line is a development-stage entity engaged in the development of long distance, high voltage direct current transmission lines that connect wind farms and other renewable resources in remote parts of the U.S. with electric demand. The Company initially committed to a $40 million investment in Clean Line, of which the Company contributed $12.5 million during the year ended March 31, 2013 and contributed the remaining $27.5 million during the year ended March 31, 2014. Based on an analysis of the contractual terms and rights contained in the related agreements, the Company determined that under the applicable accounting standards, Clean Line is a variable interest entity and the Company has effective control over the entity. Therefore, as the primary beneficiary, the Company has consolidated Clean Line. Upon consolidation, the Company recognized approximately $20 million of goodwill.

The fair value of the Clean Line reporting unit was calculated in the annual goodwill impairment test for the year ended March 31, 2015 solely utilizing the income approach. Due to the fact that Clean Line is only at the development stage of its life cycle, its discounted cash flow model has been prepared using specific assumptions, rather than the general assumptions used in relation to National Grid’s longstanding operating companies as discussed in Note 2, “Summary of Significant Accounting Policies” under “Goodwill.” The annual impairment test yielded a negative implied fair value of goodwill for the Clean Line reporting unit, and an impairment of $22 million has been recognized for the year ended March 31, 2015.

13. ENVIRONMENTAL MATTERS

The normal ongoing operations and historic activities of the Company are subject to various federal, state and local environmental laws and regulations. Under federal and state Superfund laws, potential liability for the historic contamination of property may be imposed on responsible parties jointly and severally, without regard to fault, even if the activities were lawful when they occurred.

Air

Genco’s generating facilities are subject to increasingly stringent emissions limitations under current and anticipated future requirements of the United States Environmental Protection Agency (“EPA”) and the New York State Department of Environmental Conservation (“DEC”). In addition to efforts to improve both ozone and particulate matter air quality, there has been an increased focus on greenhouse gas emissions in recent years. Genco’s previous investments in low NOx boiler combustion modifications, the use of natural gas firing systems at its steam electric generating stations, and the compliance flexibility available under cap and trade programs have enabled Genco to achieve its prior emission reductions in a cost-effective manner. Recently completed investments include the installation of enhanced NOx controls and efficiency improvement projects at certain of Genco’s Long Island based electric generating facilities. The total cost of these improvements was approximately $103 million, all of which have been placed in service as of the date of this report; a mechanism for recovery from LIPA of these investments has been established. Genco has developed a compliance strategy to address anticipated future requirements and is closely monitoring the regulatory developments to identify any necessary changes to its compliance strategy. At this time, Genco is unable to predict what effect, if any, these future requirements will have on its consolidated financial position, results of operations, and cash flows.

Water

Additional capital expenditures associated with the renewal of the surface water discharge permits for Genco's power plants will likely be required by the DEC at each of the Long Island power plants pursuant to Section 316 of the Clean Water Act to mitigate the plants' alleged cooling water system impacts to aquatic organisms. Genco is currently engaged in discussions with the DEC and environmental groups regarding the nature of capital upgrades or other mitigation measures necessary to reduce any impacts. Although these discussions have been productive and have led to mutually agreeable final permits at some of the plants, it is possible that the determination of required capital improvements and the issuance of final renewal permits for the remaining plants could involve adjudicatory hearings among Genco, the agency, and the environmental groups. Capital costs for expected mitigation requirements at the plants had been estimated at approximately $76 million and do not anticipate a need for cooling towers at any of the plants. Depending on the outcome of the adjudicatory process, which could extend beyond the next fiscal year, ultimate costs could be substantially higher. Costs associated with any finally ordered capital improvements would be reimbursable from LIPA under the PSA.

Land, Manufactured Gas Plants and Related Facilities

Federal and state environmental regulators, as well as private parties, have alleged that several of the Company's subsidiaries are potentially responsible parties under Superfund laws for the remediation of numerous contaminated sites in New York and New England. The Company's greatest potential Superfund liabilities relate to MGP facilities formerly owned or operated by its subsidiaries or their predecessors. MGP byproducts included fuel oils, hydrocarbons, coal tar, purifier waste and other waste products which may pose a risk to human health and the environment.

Since July 12, 2006, several lawsuits have been filed which allege damages resulting from contamination associated with the historic operations of a former manufactured gas plant located in Bay Shore, New York. KeySpan has been conducting a remediation at this location pursuant to Administrative Order on Consent ("ACO") with the DEC. KeySpan intends to contest these proceedings vigorously.

On February 8, 2007, the Company received a Notice of Intent to File Suit from the AG against KeySpan and four other companies in connection with the cleanup of historical contamination found in certain lands located in Greenpoint, Brooklyn and in an adjoining waterway. KeySpan has previously agreed to remediate portions of the properties referenced in this notice and will work cooperatively with the DEC and AG to address environmental conditions associated with the remainder of the properties. KeySpan has entered into an ACO with the DEC for the land-based sites. The EPA assumed control of the waterway and, on September 29, 2010, listed this site on its National Priorities List of Superfund sites. The Company signed a consent decree with the EPA on July 7, 2011 and is currently performing a Remedial Investigation and Feasibility Study. At this time, the Company is unable to predict what effect, if any, the outcome of these proceedings will have on its consolidated financial position, results of operations, and cash flows.

Utility Sites

At March 31, 2015, the Company's total reserve for estimated MGP-related environmental matters is $1.3 billion. The potential high end of the range at March 31, 2015 is presently estimated at $2.1 billion on an undiscounted basis. Management believes that obligations imposed on the Company because of the environmental laws will not have a material adverse effect on its operations, financial position, or cash flows. Through various rate orders issued by the NYPSC, DPU, and RIPUC, costs related to MGP environmental cleanup activities are recovered in rates charged to gas distribution customers. Accordingly, the Company has reflected a regulatory asset of $1.7 billion on the consolidated balance sheets at March 31, 2015 and 2014.

Upon the acquisition of KeySpan by NGUSA, the Company recognized those environmental liabilities at fair value. The fair values included discounting of the reserve, which is being accreted over the period for which remediation is expected to occur. Following the acquisition, these environmental liabilities are recognized in accordance with the current accounting guidance for environmental obligations.

The Company is pursuing claims against other potentially responsible parties to recover investigation and remediation costs it believes are the obligations of those parties. The Company cannot predict the likelihood of success of such claims.

Non-Utility Sites

The Company is aware of numerous non-utility sites for which it may have, or share, environmental remediation or ongoing maintenance responsibility. Expenditures incurred were approximately $1 million and $2 million for the years ended March 31, 2015 and 2014, respectively. The Company presently estimates the remaining cost of the environmental cleanup activities for these non-utility sites will be approximately $26 million and $24 million, which has been accrued at March 31, 2015 and 2014, respectively. The Company's environmental obligation is net of a discount rate of 6.5%, and the undiscounted amount totaled $32 million and $29 million in liabilities as of March 31, 2015 and 2014, respectively. The Company believes this to be a reasonable estimate of probable costs for known sites; however, remediation costs for each site may be materially higher than noted, depending upon changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered.

The Company believes that in the aggregate, the accrued liability for all of the sites and related facilities identified above are reasonable estimates of the probable cost for the investigation and remediation of these sites and facilities. As circumstances warrant, the Company periodically re-evaluates the accrued liabilities associated with MGP sites and related facilities. The Company may be required to investigate and, if necessary, remediate each site previously noted, or other currently unknown former sites and related facility sites, the cost of which is not presently determinable.

The Company believes that its ongoing operations, and its approach to addressing conditions at historic sites, are in substantial compliance with all applicable environmental laws, and that the obligations imposed on it because of the environmental laws will not have a material impact on its results of operations or financial position since, as noted above, environmental expenditures incurred by the Company are generally recoverable from customers.

14. COMMITMENTS AND CONTINGENCIES

Operating Lease Obligations

The Company has various operating leases for buildings, office equipment, vehicles and power operating equipment utilized by both the Company and its subsidiaries. Total rental expense for operating leases included in operations and maintenance expense in the accompanying consolidated statements of income was $97 million and $121 million for the years ended March 31, 2015 and 2014, respectively.

The future minimum lease payments for the years subsequent to March 31, 2015 are as follows:

(in millions of dollars)		
Years Ending March 31,		
2016	$	98
2017		98
2018		98
2019		84
2020		58
Thereafter		363
Total	$	799

Purchase Commitments

The Company's electric subsidiaries have several long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the subsidiaries are obligated to make payment. The Company's gas distribution subsidiaries have entered into various contracts for gas delivery, storage and supply services. Certain of these contracts require payment of annual demand charges. The Company's gas distribution subsidiaries are liable for these payments regardless of the level of services required from third-parties. Such charges are currently recovered from customers as gas costs. In addition, the Company has various capital commitments related to the construction of property, plant and equipment.

The Company's commitments under these long-term contracts for the years subsequent to March 31, 2015 are summarized in the table below:

(in millions of dollars) Years Ending March 31,	Energy Purchases	Capital Expenditures
2016	$ 1,801	$ 407
2017	898	60
2018	666	60
2019	502	45
2020	420	30
Thereafter	2,070	-
Total	$ 6,357	$ 602

The Company's subsidiaries can purchase additional energy to meet load requirements from independent power producers, other utilities, energy merchants or on the open market through the NYISO or the ISO-NE at market prices.

Financial Guarantees

The Company has guaranteed the principal and interest payments on certain outstanding debt of its subsidiaries. Additionally, the Company has issued financial guarantees in the normal course of business, on behalf of its subsidiaries, to various third-party creditors. At March 31, 2015, the following amounts would have to be paid by the Company in the event of non-payment by the primary obligor at the time payment is due:

Guarantees for Subsidiaries:		Amount of Exposure *(in millions of dollars)*	Expiration Dates
Industrial Development Revenue Bonds	(i)	$ 128	June 2027
KeySpan Ravenswood LLC Lease	(ii)	350	May 2040
Reservoir Woods	(iii)	212	October 2029
Surety Bonds	(iv)	218	Revolving
Commodity Guarantees and Other	(v)	95	October 2015 - August 2042
Letters of Credit	(vi)	198	July 2015 - February 2016
NY Transco Parent Guaranty	(vii)	842	None
		$ 2,043	

The following is a description of the Company's outstanding subsidiary guarantees:

(i) KeySpan has fully and unconditionally guaranteed the payment obligations of its subsidiaries with regard to \$128 million of Industrial Development Revenue Bonds issued through the Nassau County and Suffolk County Industrial Development Authorities for the construction of two electric-generation peaking plants on Long Island, New York. The face value of these notes is included in long-term debt in the accompanying consolidated balance sheets.

(ii) The Company had guaranteed all payment and performance obligations of a former subsidiary (KeySpan Ravenswood LLC) associated with a merchant electric generating facility leased by that subsidiary under a sale/leaseback arrangement. The subsidiary and the facility were sold in 2008. However, the original lease remains in place and the Company will continue to make the required payments under the lease through 2040. The cash consideration from the buyer of the facility included the remaining lease payments on a net present value basis. At March 31, 2015, the Company's obligation related to the lease was $151 million and is reflected in other non-current liabilities in the accompanying consolidated balance sheets.

(iii) The Company has fully and unconditionally guaranteed $229 million in lease payments through 2029 related to the lease of office facilities by its service company at Reservoir Woods in Waltham, Massachusetts.

(iv) The Company has agreed to indemnify the issuers of various surety bonds associated with various construction requirements or projects of its subsidiaries. In the event that the Company or its subsidiaries fail to perform their obligations under contracts, the injured party may demand that the surety make payments or provide services under the bond. The Company would then be obligated to reimburse the surety for any expenses or cash outlays it incurs.

(v) The Company has guaranteed commodity-related payments for certain subsidiaries. These guarantees are provided to third-parties to facilitate physical and financial transactions involved in the purchase and transportation of natural gas, oil and other petroleum products for gas and electric production and marketing activities. The guarantees cover actual purchases by these subsidiaries that are still outstanding as of March 31, 2015.

(vi) The Company has arranged for stand-by letters of credit to be issued to third-parties that have extended credit to certain subsidiaries. Certain vendors require the posting of letters of credit to guarantee subsidiary performance under the Company's contracts and to ensure payment to the Company's subsidiary subcontractors and vendors under those contracts. Certain of the Company's vendors also require letters of credit to ensure reimbursement for amounts they are disbursing on behalf of the Company's subsidiaries, such as to beneficiaries under the Company's self-funded insurance programs. Such letters of credit are generally issued by a bank or similar financial institution. The letters of credit commit the issuer to pay specified amounts to the holder of the letter of credit if the holder demonstrates that the Company has failed to perform specified actions. If this were to occur, the Company would be required to reimburse the issuer of the letter of credit.

(vii) The Company has entered into a Parent Guaranty (the "Guaranty") dated November 14, 2014 for the benefit of NY Transco LLC, which Guaranty irrevocably and unconditionally guarantees all of Grid NY LLC's payment obligations under the New York Transco Limited Liability Company Agreement ("NY Transco LLC Agreement") dated November 14, 2014 entered into by and among Consolidated Edison Transmission, LLC, Grid NY LLC, Iberdrola USA Networks, NY Transco, LLC and Central Hudson Electric Transmission LLC. Grid NY LLC's payment obligations relate to, but are not limited to, funding project development of the initial projects, obtaining initial regulatory approvals and making capital contributions as set forth in the LLC Agreement.

As of the date of this report, the Company has not had a claim made against it for any of the above guarantees and has no reason to believe that the Company's subsidiaries or former subsidiaries will default on their current obligations. However, the Company cannot predict when, or if, any defaults may take place or the impact any such defaults may have on its consolidated results of operations, financial position, or cash flows.

Long-term Contracts for Renewable Energy

Town of Johnston Project

In June 2010, pursuant to a 2009 Rhode Island law that required Narragansett to negotiate a contract for an electric generating project fueled by landfill gas from the Rhode Island Central Landfill Narragansett entered into a contract with Rhode Island LFG Genco for the Town of Johnston Project, a combined cycle power plant with an average output of 32 megawatts ("MW"). The facility reached commercial operation on May 28, 2013 and is being accounted for as an operating lease.

Deepwater Agreement

The 2009 Rhode Island law also required Narragansett to solicit proposals for a small scale renewable energy generation project of up to eight wind turbines with an aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham. The renewable energy generation project also included a transmission cable to be constructed between Block Island and the mainland of Rhode Island. On June 30, 2010, Narragansett entered into a 20-year Amended Power Purchase Agreement ("PPA") with Deepwater Wind Block Island LLC, which was approved by the RIPUC in August 2010. Narragansett also negotiated a Transmission Facilities Purchase Agreement ("Facilities Purchase Agreement") with Deepwater Wind Block Island Transmission, LLC ("Deepwater") to purchase from Deepwater the permits, engineering, real estate, and other site development work for construction of the undersea transmission cable (collectively, the "Transmission Facilities"). On April 2, 2014, the Division issued its Consent Decision for Narragansett to execute the Facilities Purchase Agreement with Deepwater. In July 2014, Narragansett filed with the FERC to recover the costs associated with the cable in transmission rates. On September 2, 2014, the FERC approved all four agreements required to implement NGUSA's cost recovery for the project, with no conditions. The agreements went into effect on September 30, 2014. On January 30, 2015, Narragansett closed on its purchase of the Transmission Facilities from Deepwater.

The Renewable Energy Growth Program

The Renewable Energy ("RE") Growth Program was established pursuant to Chapter 26.6 of Title 39 of the Rhode Island General Laws under the recently-enacted Clean Energy Jobs Program Act (the "Act") to encourage growth of renewable generation in Rhode Island by 160 MW. Pursuant to the Act, Narragansett is required to purchase the output generated by eligible Distributed Generation projects that have been selected for participation in the RE Growth Program and to compensate program applicants in the form of Performance Based Incentive ("PBI") Payments. Participants will be subject to the terms and conditions of the RE Growth Program tariffs approved by the RIPUC and will be compensated via PBI Payments pursuant to those tariffs, which will be in effect for up to 20 years. The Act provides for the recovery of the incremental costs incurred by Narragansett associated with the implementation and administration of the RE Growth Program from all retail delivery service customers through a fixed monthly charge per customer. Costs eligible for recovery include the PBI Payments less the net proceeds from the sale of the energy and the RE Certificates generated by each project into the market, plus all incremental administrative costs. In addition, the Act authorizes Narragansett to earn 1.75% of the total PBI Payments as remuneration.

Legal Matters

The Company is subject to various legal proceedings, primarily injury claims, arising out of the ordinary course of its business. The Company does not consider any of such proceedings to be material, individually or in the aggregate, to its business or likely to result in a material adverse effect on its results of operations, financial position, or cash flows.

FERC ROE Complaints

On September 30, 2011, several state and municipal parties in New England, ("Complainants"), filed a complaint against certain New England Transmission Owners, ("NETOs") including NEP, to lower the base ROE for transmission rates in New England from 11.14% to 9.2 %. On August 6, 2013, a FERC Administrative Law Judge ("ALJ") issued an Initial Decision finding that the base ROE for the refund period and the prospective period should be 10.6% and 9.7%, respectively, prior to any adjustments in a final FERC order. The refund period is the 15-month period from October 1, 2011 through December 31, 2012; the prospective period begins when the FERC issues its final order. In response to the ALJ's Initial Decision, NEP recorded an estimated reduction to revenues of $7.1 million and an increase to interest expense of $0.2 million for the fiscal year ended March 31, 2013, reflecting an effective ROE of 10.6% for the portion that would be refunded to transmission customers for the refund period. On June 19, 2014, the FERC issued Opinion No. 531, an initial order modifying the ALJ's findings and its previous methodology for establishing ROE. The FERC tentatively set the ROE at 10.57% and capped the ROE for incentive rates of return to 11.74% subject to further proceedings to establish and quantify growth rates applicable to the ROE. In response, NEP recorded an additional reduction to revenues of $1.2 million and an increase of $0.2 million to interest expense for the fiscal year ended March 31, 2014.

On October 16, 2014, the FERC issued a final order in Opinion No. 531-A establishing a 10.57% base ROE for the NETOs effective as of October 16, 2014 and capped the ROE, including incentives, at 11.74%. The FERC also directed that refunds be issued to transmission customers taking service during the 15-month refund period from October 1, 2011 through December 31, 2012 to reflect these reductions. On March 3, 2015, the FERC issued an Order on Rehearing, Opinion No. 531-B, affirming the 10.57% base ROE and clarifying that the 11.74% maximum ROE applies to all individual transmission projects with ROE incentives previously granted by the FERC. A further compliance filing will be submitted to the FERC shortly to clarify the applications of the 11.74% ROE cap.

On December 27, 2012, a second ROE complaint was filed against the NETOs by a coalition of consumers seeking to lower the base ROE for New England transmission rates to 8.7% effective as of December 27, 2012. On June 19, 2014, the FERC issued an order setting the complaint for investigation and a trial-type, evidentiary hearing. The FERC stated that it expects parties to present evidence and any discounted cash flow analyses, as guided by the rulings found in FERC's June 19 order on the first complaint. The FERC's order also established a 15-month refund period for the second complaint beginning on December 27, 2012. In its order setting the complaint for hearing, the FERC noted that, if the case is fully litigated, the FERC expects to issue its final decision no earlier than April 30, 2016.

On July 31, 2014, a third ROE Complaint was filed against the NETOs by the Complainants. The FERC has not yet acted on this complaint.

Electric Services and LIPA Agreements

Effective May 28, 2013, Genco provides services to LIPA under an amended and restated PSA. Under the PSA, Genco has a revenue requirement of $418.6 million, a ROE of 9.75% and a capital structure of 50% debt and 50% equity. The PSA has a term of fifteen years, provided LIPA has the option to terminate the agreement as early as April 2025 on two years advance notice. Genco accounts for the PSA as an operating lease.

The PSA provides potential penalties to Genco if it does not maintain the output capability of the generating facilities, as measured by annual industry-standard tests of operating capability, plant availability, and efficiency. These penalties may total $4 million annually. Although the PSA provides LIPA with all of the capacity from the generating facilities, LIPA has no obligation to purchase energy from the generating facilities and can purchase energy on a least-cost basis from all available sources consistent with existing transmission interconnection limitations of the transmission and distribution system. Genco must, therefore, operate its generating facilities in a manner such that the Company can remain competitive with other producers of energy. To date, Genco has dispatched to LIPA and LIPA has accepted the level of energy generated at the agreed to price per megawatt hour. Under the terms of the PSA, LIPA is obligated to pay for capacity at rates that reflect recovery of an agreed level of the overall cost of maintaining and operating the generating facilities, including recovery of depreciation and return on its investment in plant. A monthly variable maintenance charge is billed for each unit of energy actually acquired from the generating facilities. The billings to LIPA under the PSA do not include a provision for fuel costs, as such fuel is owned by LIPA.

In June 2011, LIPA and Genco executed an amendment to the then-current PSA pursuant to which the parties agreed that LIPA would reduce purchases of capacity from specified generating facilities, specifically the Glenwood and Far Rockaway, New York steam facilities. The Company has retired these generating facilities and removed them from the PSA and is in the process of dismantling these facilities. As part of this amendment, Genco paid an Economic Equivalent Payment ("EEP") of

$18 million which represented the economic benefit to LIPA which would have been realized under the original agreement. Half of the EEP was paid on July 3, 2012, with the remaining balance on May 28, 2013. The EEP was accrued on a straight-line basis over the 24-month term, from June 2011 through May 2013, as a reduction in operating revenues.

Pursuant to the EMA, the Company procured and managed fuel supplies for LIPA to fuel the Company's Long Island based generating facilities. In exchange for these services, the Company earned an annual fee of $750,000. The EMA expired on May 28, 2013. LIPA did not renew the EMA contract with the Company.

Decommissioning Nuclear Units

NEP has minority interests in three nuclear generating companies: Yankee Atomic Electric Company ("Yankee Atomic"), Connecticut Yankee Atomic Power Company ("Connecticut Yankee"), and Maine Yankee Atomic Power Company ("Maine Yankee") (together, the "Yankees"). These ownership interests are accounted for on the equity method. The Yankees operated nuclear generating units which have been permanently shut down and physically decommissioned. Spent nuclear fuel remains on each site, awaiting fulfillment by the DOE of its statutory and contractual obligation to remove it. Future estimated billings, which are included in other non-current liabilities and other current liabilities in the accompanying consolidated balance sheets, are as follows:

(in thousands of dollars)	NEP's Investment as of March 31, 2015			Future Estimated Billings to the Company
Unit	%	Amount	Date Retired	Amount
Yankee Atomic	34.5	$ 520	Feb 1992	$ 3,685
Connecticut Yankee	19.5	317	Dec 1996	14,921
Maine Yankee	24.0	593	Aug 1997	7,913

The Yankees are periodically required to file rate cases for FERC review, which present the Yankees' estimated future decommissioning costs. The Yankees collect the approved costs from their purchasers, including NEP. Future estimated billings from the Yankees are based on cost estimates. These estimates include the projections of groundwater monitoring, security, liability and property insurance and other costs. They also include costs for interim spent fuel storage facilities which the Yankees have constructed while they await removal of the fuel by the DOE as required by the Nuclear Waste Policy Act of 1982 and contracts between the DOE and each of the Yankees. NEP has recorded a liability and a regulatory asset reflecting the estimated future decommissioning billings from the Yankees.

In 2013, the FERC accepted settlements establishing rate mechanisms by which each of the Yankees maintains funding for operations and decommissioning and credits to its purchasers, including NEP, any net proceeds in excess of funding costs received as part of the DOE litigation proceedings discussed below.

Each of the Yankees brought litigation against the DOE for failure to remove their respective nuclear fuel stores as required by the Nuclear Waste Policy Act and contracts. Following a trial at the U.S. Court of Claims ("Claims Court") to determine the level of damages, on October 4, 2006, the Claims Court awarded the three companies an aggregate of $143 million for spent fuel storage costs that had been incurred through 2001 and 2002 (the "Phase I Litigation"). The Yankees had requested $176.3 million. The DOE appealed to the U.S. Court of Appeals for the Federal Circuit, which rendered an opinion generally supporting the Claims Court's decision and remanded the matter to it for further proceedings. In September, 2010, the Claims Court again awarded the companies an aggregate of approximately $143 million. The DOE again appealed and the Yankees cross-appealed. On May 18, 2012, the Court of Appeals again ruled in favor of the Yankees, awarding them an aggregate of approximately $160 million. The DOE sought reconsideration but, on September 5, 2012, the Court of Appeals for the Federal Circuit denied the petition for rehearing. The DOE elected not to file a petition for writ of certiorari seeking review by the U.S. Supreme Court and in January 2013 the awards were paid to the Yankees. As of March 31, 2015, total net proceeds of $20.9 million have been refunded to NEP by Connecticut Yankee and Maine Yankee. Yankee Atomic did not provide a refund, but reduced monthly billing effective June 1, 2013. The Company will refund its share to its customers through the CTCs.

On December 14, 2007, the Yankees brought further litigation in the Claims Court to recover subsequent damages incurred through 2008 (the “Phase II Litigation”). A Claims Court trial took place in October 2011. On November 1, 2013, the judge awarded the Yankees an aggregate of $235.4 million in damages for the Phase II Litigation. The DOE elected not to seek appellate review and the awards were paid to the Yankees. As of March 31, 2015 total net proceeds of $57.9 million have been refunded to the Company by the Yankees. The Company will refund its share of the net proceeds to its customers through the CTCs.

On August 15, 2013 the Yankees brought further litigation in the Claims Court to recover damages incurred from 2009 through 2012.

The U.S. Congress and the DOE have effectively terminated budgetary support for the proposed long-term spent fuel storage facility at Yucca Mountain in Nevada and the DOE took actions designed to prevent its construction. However, on August 12, 2013 the U.S. Court of Appeals for the District of Columbia Circuit directed the Nuclear Regulatory Commission (“NRC”) to resume the Yucca Mountain licensing process despite insufficient funding to complete it. On October 28, 2013, the Circuit Court denied the NRC’s petition for rehearing. On November 18, 2013, NRC ordered its staff to resume work on its Yucca Mountain safety report. A Blue Ribbon Commission (“BRC”) charged with advising the DOE regarding alternatives to disposal at Yucca Mountain issued its final report on January 26, 2012. In the report, the BRC recommended that priority be given to removal of spent fuel from shutdown reactor sites. It is impossible to predict when the DOE will fulfill its obligation to take possession of the Yankees’ spent fuel. The decommissioning costs that are actually incurred by the Yankees may substantially exceed the estimated amounts.

Nuclear Contingencies

As of March 31, 2015 and 2014, Niagara Mohawk had a liability of $168 million, recorded in other non-current liabilities in the accompanying consolidated balance sheets, for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Policy Act of 1982 provides three payment options for liquidating such liability and Niagara Mohawk has elected to delay payment, with interest, until the year in which Constellation Energy Group Inc., which purchased Niagara Mohawk’s nuclear assets, initially plans to ship irradiated fuel to an approved DOE disposal facility. Niagara Mohawk cannot predict the impact that the recent actions of the DOE and the U.S. government will have on the ability to dispose of the spent nuclear fuel and waste.

SuperStorm Sandy

In October 2012, SuperStorm Sandy hit the northeastern U.S. affecting energy supply to customers in the Company’s service territory. Total costs associated with gas customer service restoration from this storm (including capital expenditures) through March 31, 2014 were approximately $204.1 million for the New York Gas Companies.

The Company had recorded an “other receivable” in the accompanying consolidated balance sheets in the amount of $58 million as of March 31, 2014, relating to claims filed against its property damage insurance policy, net of insurance deductibles, allowances, and advance payments received. In December 2014, the Company reached a final settlement with its insurers for $155 million (inclusive of advance payments of $83.4 million), and received final payment for the remaining amounts due. This resulted in the Company recognizing a gain of $11.1 million for the year ended March 31, 2015, recorded as a reduction to operations and maintenance expense in the accompanying consolidated statements of income.

15. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

The Company engages in various transactions with the Parent and its subsidiaries. Certain activities and costs, primarily executive and administrative and some human resources, legal, and strategic planning are shared between the Company and its affiliates.

The Company records short-term receivables from, and payables to, certain of its affiliates in the ordinary course of business. A summary of net outstanding accounts receivable from affiliates and accounts payable to affiliates is as follows:

	Accounts Receivable from Affiliates		Accounts Payable to Affiliates	
	March 31,		March 31,	
	2015	2014	**2015**	2014
	(in millions of dollars)		*(in millions of dollars)*	
National Grid plc	**$ -**	$ -	**$ 52**	$ 60
National Grid Holdings One plc	**-**	-	**9**	8
Other	**1**	1	**2**	3
Total	**$ 1**	$ 1	**$ 63**	$ 71

Advance from Affiliate

In August 2009, NGUSA and KeySpan Corporation entered into an agreement with the Parent, whereby either party can collectively borrow up to $3 billion from time to time for working capital needs. These advances bear interest rates of LIBOR plus 1.4%. At March 31, 2015 and 2014, the Company had zero and $750 million outstanding under this agreement.

Holding Company Charges

The Company received charges from National Grid Commercial Holdings Limited (an affiliated company in the U.K.) for certain corporate and administrative services provided by the corporate functions of the Parent to its U.S. subsidiaries. For the years ended March 31, 2015 and 2014, the effect on net income was $45 million and $52 million before taxes and $27 million and $34 million after taxes.

16. PREFERRED STOCK

Preferred stock of NGNA subsidiaries

The Company's subsidiaries have certain issues of non-participating preferred stock, some of which provide for redemption at the option of the Company. A summary of the preferred stock of NGNA subsidiaries at March 31, 2015 and 2014 is as follows:

		Shares Outstanding		Amount		
		March 31,		March 31,		Call
Series	Company	**2015**	2014	**2015**	2015	**Price**
		(in millions of dollars, except per share and number of shares data)				
$100 par value -						
3.40% Series	Niagara Mohawk	**57,524**	57,524	**$ 6**	$ 6	$ 103.500
3.60% Series	Niagara Mohawk	**137,152**	137,152	**14**	14	104.850
3.90% Series	Niagara Mohawk	**95,171**	95,171	**9**	9	106.000
4.44% Series	Massachusetts Electric	**22,585**	22,585	**2**	2	104.068
6.00% Series	NEP	**11,117**	11,117	**1**	1	Non-callable
$50 par value -						
4.50% Series	Narragansett	**49,089**	49,089	**3**	3	55.000
Golden Shares -						
	Niagara Mohawk and KeySpan subsidiaries	**3**	3	**-**	-	Non-callable
Total		**372,641**	372,641	**$ 35**	$ 35	

In connection with the acquisition of KeySpan by NGUSA, each of the Company's New York subsidiaries became subject to a requirement to issue a class of preferred stock, having one share (the "Golden Share"), subordinate to any existing preferred stock. The holder of the Golden Share would have voting rights that limit the Company's right to commence any voluntary bankruptcy, liquidation, receivership or similar proceeding without the consent of the holder of the Golden Share. The NYPSC subsequently authorized the issuance of the Golden Share to a trustee, GSS Holdings, Inc. ("GSS"), who will hold the Golden Share subject to a Services and Indemnity Agreement requiring GSS to vote the Golden Share in the best interests of New York state. On July 8, 2011, the Company issued a total of 3 Golden Shares pertaining to Niagara Mohawk, Brooklyn Union, and KeySpan Gas East each with a par value of $1.

17. STOCK-BASED COMPENSATION

The Parent's Remuneration Committee determines remuneration policy and practices with the aim of attracting, motivating and retaining high caliber Executive Directors and other senior employees to deliver value for shareholders, high levels of customer service, and safety and reliability in an efficient and responsible manner. As such, the Remuneration Committee has established a Long-Term Performance Plan ("LTPP") which aims to drive long-term performance, aligning Executive Director incentives to shareholder interests. The LTPP replaces the previous Performance Share Plan ("PSP") which operated for awards between 2003 and 2010 inclusive. Both plans issue performance based restricted stock units ("RSU"s) which are granted in the Parent's common stock traded on the London Stock Exchange for U.K.-based directors and employees or the Parent's American Depository Receipts traded on the New York Stock Exchange for U.S.-based directors and employees. Both plans have a performance period of three years and have been approved by the Parent's Remuneration Committee.

As of March 31, 2015, the Parent had 3.9 billion of ordinary shares issued with 152,945,477 held as treasury shares. The aggregate dilution resulting from executive share-based incentives will not exceed 5% in any ten year period for executive share-based incentives and will not exceed 10% in any ten year period for all employee incentives. This is reviewed by the Remuneration Committee and currently, the Parent has excess headroom of 4.12% and 7.95%, respectively.

The number of units within each award is subject to change depending upon the Parent's ability to meet the stated performance targets. Under the LTPP, performance conditions are split into three parts as follows: (i) 50% of the units awarded are subject to annualized growth in the Parent's earnings per share ("EPS") over a general index of retail prices over a period of three years; (2) 25% of the units awarded will vest based upon the Parent's Total Shareholder Return ("TSR") compared to that of the Financial Times Stock Exchange ("FTSE") 100 over a period of three years; and (3) 25% of the units awarded are subject to the average achieved regulatory ROE. Under the PSP, performance conditions are split into two parts as follows: (1) 50% of the units awarded are subject to annualized growth in the Parent's EPS over a general index of retail prices over a period of three years; and (2) 50% of the units awarded will vest based upon the Parent's TSR compared to that of the FTSE 100 over a period of three years. Units under both plans generally vest at the end of the performance period.

A Monte Carlo simulation model has been used to estimate the fair value for the TSR portion of the awards. For the EPS and ROE portions of the awards, the fair value of the award is determined using the stock price as quoted per the London Stock Exchange or the price for the American Depository Shares as quoted on the New York Stock Exchange as of the earlier of the reporting date or vesting date.

The following table summarizes the stock based compensation expense recognized by the Company for the years ended March 31, 2015 and 2014:

	Units	Weighted Average Grant Date Fair Value
Non-vested as of March 31, 2013	945,945	$ 40.36
Vested	183,275	46.37
Granted	247,891	55.96
Forfeited/Cancelled	89,829	49.00
Non-vested as of March 31, 2014	920,732	49.92
Vested	351,669	45.95
Granted	408,730	68.26
Forfeited/Cancelled	122,169	55.86
Non-vested as of March 31, 2015	855,624	$ 60.65

The total expense recognized for non-vested awards was $15.5 million and $19 million for the years ended March 31, 2015 and 2014, respectively, and will vest over three years. The total tax benefit recorded was approximately $6.2 million and $7.6 million as of March 31, 2015 and 2014, respectively. Total expense expected to be recognized by the Parent in future periods for non-vested awards outstanding as of March 31, 2015 is $12 million, $8.5 million, and $2.8 million for the years ended March 31, 2016, 2017, and 2018, respectively.

18. DISCONTINUED OPERATIONS

On December 15, 2011, LIPA announced that it was not renewing the MSA contract beyond its expiration on December 31, 2013. The loss of the contract resulted in 1,950 employees transferring to a new employer. The results of the MSA are reflected as discontinued operations in the accompanying consolidated financial statements for the years ended March 31, 2015 and 2014.

Following the expiration of the MSA, NGUSA entered into a Settlement and Release Agreement ("SRA") with LIPA. Under the terms of this SRA, LIPA (1) fully released NGUSA from its obligations under certain promissory notes payable to LIPA, and (2) agreed to make a one-time lump sum payment to NGUSA of $91.5 million. In return, during the year ended March 31, 2014, NGUSA fully released LIPA from certain claims for reimbursement of pension and PBOP costs. As a result, NGUSA recorded a gain of approximately $231 million, primarily related to the extinguishment of debt and recognition of a receivable for the lump sum cash payment during the year ended March 31, 2014.

In addition, during the year ended March 31, 2014, a $97 million net settlement gain and a $43 million net curtailment gain were recognized for the employees who transferred to a new employer. The new employer had assumed responsibility for the transferred employees' obligations under the PBOP.

The reconciliation below highlights the financial statements line items within income from discontinued operations, net of taxes for the MSA for the years ended March 31, 2015 and 2014:

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Operating revenues	**$ 97**	$ 476
Operations and maintenance	**(69)**	(601)
Other expenses	**(8)**	(19)
Other deductions	**(2)**	-
Income (loss) before income taxes	**18**	(144)
Gain on disposal of discontinued operations	**-**	371
Total income before income taxes	**18**	227
Income tax (benefit) expense	**6**	94
Income from discontinued operations, net of taxes	**$ 12**	$ 133

The reconciliation below highlights the carrying values of assets and liabilities related to discontinued operations that are disclosed in the accompanying consolidated balance sheets for the MSA at March 31, 2015 and 2014:

	March 31,	
	2015	2014
	(in millions of dollars)	
Assets		
Accounts receivable	**$ 100**	$ 219
Allowance for doubtful accounts	**(70)**	(70)
Unbilled revenues	**11**	2
Deferred income tax assets	**29**	29
Other	**-**	2
Total assets related to discontinued operations	**$ 70**	$ 182
Liabilities		
Accounts payable	**$ 20**	$ 20
Taxes accrued	**1**	2
Other	**-**	15
Total liabilities related to discontinued operations	**$ 21**	$ 37

19. SUBSEQUENT EVENTS

Subsequent to March 31, 2015, the Company raised $885.9 million through the Euro Medium Term Note program by issuing a series of fixed rate instruments with maturity dates ranging from July 2018 through June 2022 and interest rates ranging from 1.96% through 3%. Further, on September 1, 2015, the Company issued a $500 million term loan with an interest rate of six month LIBOR plus a margin spread of 0.2% and a maturity date of March 1, 2016.