nationalgrid

National Grid USA and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2016 and 2015

NATIONAL GRID USA AND SUBSIDIARIES

TABLE OF CONTENTS

Independent Auditor's Report

To the Board of Directors
of National Grid USA

We have audited the accompanying consolidated financial statements of National Grid USA and its subsidiaries (the Company), which comprise the consolidated balance sheets and statements of capitalization as of March 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, cash flows, and changes in shareholders' equity for the years then ended.

Management's Responsibility for the Consolidated 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 consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated 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 USA and its subsidiaries as of March 31, 2016 and 2015, 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 26, 2016

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NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(in millions of dollars)

	Years Ended March 31,	
	2016	2015
Operating revenues:		
Electric services	**$ 6,667**	$ 7,142
Gas distribution	**4,316**	5,234
Other	**25**	64
Total operating revenues	**11,008**	12,440
Operating expenses:		
Purchased electricity	**1,948**	2,514
Purchased gas	**1,301**	2,201
Operations and maintenance	**4,282**	4,608
Depreciation and amortization	**1,006**	953
Other taxes	**1,099**	1,087
Total operating expenses	**9,636**	11,363
Operating income	**1,372**	1,077
Other income and (deductions):		
Interest on long-term debt	**(386)**	(393)
Other interest, including affiliate interest	**(80)**	(74)
Income from equity investments	**33**	41
Gain on sale of assets	**76**	-
Unrealized gains on investment in Dominion Midstream Partners, LP	**53**	-
Other deductions, net	**(12)**	(79)
Total other deductions, net	**(316)**	(505)
Income before income taxes	**1,056**	572
Income tax expense	**402**	200
Income from continuing operations	**654**	372
(Loss) income from discontinued operations, net of taxes	**(13)**	10
Net income	**641**	382
Net loss attributable to non-controlling interest	**-**	18
Dividends paid on preferred stock	**(1,179)**	-
Net (loss) income attributable to common shares	**$ (538)**	$ 400

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions of dollars)

	Years Ended March 31,	
	2016	2015
Net income	**$ 641**	$ 382
Other comprehensive income (loss), net of taxes:		
Unrealized (losses) gains on securities	**(4)**	6
Change in pension and other postretirement obligations	**42**	(238)
Unrealized gains (losses) on hedges	**1**	(1)
Total other comprehensive income (loss)	**39**	(233)
Comprehensive income	**$ 680**	$ 149
Less: comprehensive loss attributable to non-controlling interest	**-**	18
Comprehensive income attributable to common and preferred shares	**$ 680**	$ 167
Related tax (expense) benefit:		
Unrealized losses (gains) on securities	**$ 3**	$ (4)
Change in pension and other postretirement obligations	**(29)**	167
Unrealized (gains) losses on hedges	**-**	1
Total tax (expense) benefit	**$ (26)**	$ 164

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions of dollars)

	Years Ended March 31, 2016	2015
Operating activities:		
Net income	**$ 641**	$ 382
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**1,006**	953
Regulatory amortizations	**115**	120
Provision for deferred income taxes	**345**	214
Bad debt expense	**191**	218
(Income) loss from equity investments, net of dividends received	**(9)**	6
Gain on sale of assets	**(76)**	-
Unrealized gains on investment in Dominion Midstream Partners, LP	**(53)**	-
Goodwill impairment	**-**	22
Allowance for equity funds used during construction	**(19)**	(19)
Amortization of debt discount and issuance costs	**12**	9
Net postretirement benefits expense	**1**	170
Net environmental remediation payments	**(118)**	(103)
Share based compensation	**21**	15
Changes in operating assets and liabilities:		
Accounts receivable and other receivable, net, and unbilled revenues	**566**	74
Accounts receivable from/payable to affiliates, net	**(36)**	(9)
Inventory	**(35)**	(46)
Regulatory assets and liabilities, net	**(3)**	(57)
Derivative instruments	**(110)**	130
Prepaid and accrued taxes	**31**	(12)
Accounts payable and other liabilities	**(190)**	(2)
Renewable energy certificate obligations, net	**(43)**	52
Other, net	**5**	66
Net cash provided by operating activities	**2,242**	2,183
Investing activities:		
Capital expenditures	**(2,572)**	(2,433)
Changes in restricted cash and special deposits	**97**	(22)
Cost of removal and other	**(175)**	(150)
Net cash used in investing activities	**(2,650)**	(2,605)
Financing activities:		
Preferred stock dividends	**(1,179)**	-
Payments on long-term debt	**(866)**	(728)
Proceeds from long-term debt	**1,221**	900
Payment of debt issuance costs	**-**	(5)
Commercial paper (paid) issued	**(284)**	161
Affiliated money pool borrowing and receivables/payables, net	**-**	4
Advances from affiliates	**1,979**	(1,093)
Payments on sale/leaseback arrangement	**(41)**	(41)
Other	**-**	5
Net cash provided by (used in) financing activities	**830**	(797)
Net increase (decrease) in cash and cash equivalents	**422**	(1,219)
Net cashflow from discontinued operations - operating	**12**	98
Net cashflow from discontinued operations - investing	**-**	-
Net cashflow from discontinued operations - financing	**-**	-
Cash and cash equivalents, beginning of year	**450**	1,571
Cash and cash equivalents, end of year	**$ 884**	$ 450
Supplemental disclosures:		
Interest paid	**$ (381)**	$ (390)
Income taxes (paid) refunded	**(4)**	22
Significant non-cash items:		
Capital-related accruals included in accounts payable	**181**	95

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31,	
	2016	2015
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 884**	$ 450
Restricted cash and special deposits	**93**	190
Accounts receivable	**2,080**	2,641
Allowance for doubtful accounts	**(406)**	(361)
Accounts receivable from affiliates	**28**	2
Unbilled revenues	**416**	567
Inventory	**481**	397
Regulatory assets	**712**	656
Derivative instruments	**15**	37
Prepaid taxes	**156**	182
Other	**82**	91
Current assets related to discontinued operations	**21**	41
Total current assets	**4,562**	4,893
Equity investments	**125**	190
Property, plant and equipment, net	**27,464**	25,595
Other non-current assets:		
Regulatory assets	**4,850**	4,903
Goodwill	**7,129**	7,129
Derivative instruments	**5**	15
Postretirement benefits asset	**187**	189
Financial investments	**693**	494
Other	**143**	127
Other non-current assets related to discontinued operations	**37**	29
Total other non-current assets	**13,044**	12,886
Total assets	**$ 45,195**	$ 43,564

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31, 2016	March 31, 2015
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 1,211**	$ 1,393
Accounts payable to affiliates	**44**	54
Advances from affiliates	**3,057**	1,078
Commercial paper	**298**	582
Current portion of long-term debt	**940**	638
Taxes accrued	**47**	46
Customer deposits	**121**	120
Interest accrued	**120**	133
Regulatory liabilities	**569**	631
Derivative instruments	**94**	262
Renewable energy certificate obligations	**193**	166
Payroll and benefits accruals	**276**	252
Other	**166**	177
Current liabilities related to discontinued operations	**23**	21
Total current liabilities	**7,159**	5,553
Other non-current liabilities:		
Regulatory liabilities	**3,020**	2,861
Asset retirement obligations	**94**	81
Deferred income tax liabilities, net	**4,989**	4,600
Postretirement benefits	**3,712**	3,839
Environmental remediation costs	**1,295**	1,336
Derivative instruments	**41**	39
Other	**891**	864
Total other non-current liabilities	**14,042**	13,620
Commitments and contingencies (Note 14)		
Capitalization:		
Shareholders' equity	**15,700**	16,177
Long-term debt	**8,294**	8,214
Total capitalization	**23,994**	24,391
Total liabilities and capitalization	**$ 45,195**	$ 43,564

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
(in millions of dollars)

			March 31, 2016	March 31, 2015
Shareholders' equity attributable to common and preferred shares			**$ 15,691**	$ 16,163
Non-controlling interest in subsidiaries			**9**	14
Long-term debt:	Interest Rate	Maturity Date		
European Medium Term Note	Variable	June 2015 - January 2016	**-**	588
Notes Payable	2.72% - 9.75%	January 2016 - March 2046	**7,328**	6,338
Promissory Notes to National Grid North America Inc.	3.13% - 3.25%	June 2027 - April 2028	**227**	-
Gas Facilities Revenue Bonds	Variable	December 2020 - July 2026	**230**	230
Gas Facilities Revenue Bonds [1]	4.7% - 6.95%	April 2020 - July 2026	**411**	411
First Mortgage Bonds	6.82% - 9.63%	April 2018 - April 2028	**124**	125
State Authority Financing Bonds	Variable	June 2015 - August 2042	**918**	1,033
Industrial Development Revenue Bonds [2]	5.25%	June 2027	**-**	128
Total debt			**9,238**	8,853
Unamortized debt discount			**(4)**	(1)
Current portion of long-term debt			**(940)**	(638)
Long-term debt			**8,294**	8,214
Total capitalization			**$ 23,994**	$ 24,391

(1) During March 2016, The Brooklyn Union Gas Company issued Notice of Optional Redemption letters to the bond holders of the fixed interest rate gas facilities revenue bonds. The Brooklyn Union Gas Company fully repaid these bonds during April 2016 as disclosed in Note 19, "Subsequent Events." Hence these bonds are classified within current portion of long-term debt.

(2) On November 20, 2015, National Grid Generation LLC redeemed this debt as disclosed in Note 10, "Capitalization."

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(in millions of dollars)

	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss): Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest	Total
Balance as of March 31, 2014	**$ -**	**$ 35**	**$ 14,137**	**$ 2**	**$ (652)**	**$ (2)**	**$ (652)**	**$ 2,460**	**$ 12**	**$ 15,992**
Net income	-	-	-	-			-	400	(18)	382
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 losses on hedges, net of $1 tax benefit	-	-	-	-	-	(1)	(1)	-	-	(1)
Total comprehensive income										149
Parent loss tax allocation	-	-	5	-	-	-	-	-	-	5
Share based compensation	-	-	15	-	-	-	-	-	-	15
Other equity transactions with non-controlling interest	-	-	(4)	-	-	-	-	-	20	16
Balance as of March 31, 2015	**$ -**	**$ 35**	**$ 14,153**	**$ 8**	**$ (890)**	**$ (3)**	**$ (885)**	**$ 2,860**	**$ 14**	**$ 16,177**
Net income	-	-	-	-			-	641	-	641
Other comprehensive income:										
Unrealized losses on securities, net of $3 tax benefit	-	-	-	(4)	-	-	(4)	-	-	(4)
Change in pension and other postretirement obligations, net of $29 tax expense	-	-	-	-	42	-	42	-	-	42
Unrealized gains on hedges, net of $0 tax expense	-	-	-	-	-	1	1	-	-	1
Total comprehensive income										680
Share based compensation	-	-	21	-	-	-	-	-	-	21
Preferred stock dividends	-	-	-	-	-	-	-	(1,179)	-	(1,179)
Other equity transactions with non-controlling interest	-	-	6	-	-	-	-	-	(5)	1
Balance as of March 31, 2016	**$ -**	**$ 35**	**$ 14,180**	**$ 4**	**$ (848)**	**$ (2)**	**$ (846)**	**$ 2,322**	**$ 9**	**$ 15,700**

The Company had 641 shares of common stock authorized, issued and outstanding, with a par value of $0.10 per share, 915 shares of preferred 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, 2016 and 2015.

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

NATIONAL GRID USA AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

National Grid USA ("NGUSA" or "the Company") is a public utility holding company with regulated subsidiaries engaged in the generation of electricity and the transmission, distribution, and sale of both natural gas and electricity. NGUSA is a direct wholly-owned subsidiary of National Grid North America Inc. ("NGNA") and an indirect wholly-owned subsidiary of National Grid plc (the "Parent"), a public limited company incorporated under the laws of England and Wales.

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 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, 2016 and 2015.

Other Services and Investments

The Company's Energy Services business includes companies that provide energy-related services to customers located primarily within the northeastern United States ("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. The Company has a wholly-owned subsidiary, National Grid LNG LLC, which is engaged in the business of receiving, storing and redelivering liquefied natural gas ("LNG") in liquid and gaseous states, through facilities located 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"), which is 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 September 29, 2015, the Company contributed its 20.4% interest in Iroquois Gas Transmission System L.P., which was accounted for under the equity method of accounting, to Dominion Midstream Partners, LP ("DM") in exchange for approximately 6.8 million common units (representing approximately a 9% interest) of DM. DM was formed to grow a portfolio of natural gas terminaling, processing, storage, and transportation assets. The transaction resulted in a gain on sale of assets of $74 million. The Company has elected the fair value option with respect to its investment in DM and as such, any changes in the fair value of these common units are recorded as unrealized gains on investment in Dominion Midstream Partners, LP in the accompanying consolidated statements of income. The Company's investment in DM is included within financial investments in the accompanying consolidated balance sheets.

On October 13, 2015, through its indirect wholly-owned subsidiary, National Grid Technologies, the Company entered into agreements with and became a limited partner of Energy Impact Fund LP ("the Fund"), which is a Delaware limited partnership set up to engage in private equity and venture capital investing, primarily through acquiring, holding, and disposing of equity securities issued by companies focused on energy impact technologies. The Fund has an initial term of 10 years and the Company has made a capital commitment of $50 million to the Fund. For the year ended March 31, 2016, the Company has made multiple capital contributions totaling $1.1 million.

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 ("RFPs") 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. From October 10, 2014 to the year ended March 31, 2016, the Company has made multiple capital contributions totaling $1.6 million. In May 2016, the Company has made two additional capital contributions totaling $31.7 million for the purchase of the Indian Point Reliability Contingency Projects which included the Ramapo Rock Tavern and Staten Island Unbottling Projects.

Through its wholly-owned subsidiary, National Grid Algonquin LLC ("NGA"), the Company entered into an agreement in September 2015 to participate in a project ("Access Northeast") with Eversource Energy and Spectra Energy Corporation to enhance the Algonquin and Maritimes & Northeast pipeline systems and construct new LNG storage tanks and vaporization facilities in Acushnet, Massachusetts that will be connected to the Algonquin gas pipeline.

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 and has not elected to account for such investments at fair value. 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.

The Company has evaluated subsequent events and transactions through September 26, 2016, 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, 2016, 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 certain cases, the rate actions of the FERC, NYPSC, DPU and RIPUC can result in accounting that differs from non-regulated companies. 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. Movements in regulatory assets and liabilities are reflected in the consolidated statements of income consistent with the treatment of the related costs in the ratemaking processes that exist at the different operating companies.

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, 2016 and 2015 were $101.1 million and $107.2 million, respectively.

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 ("NYS") 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 determines its current and deferred taxes based on the separate return method, modified by benefits-for-loss allocation pursuant to a tax sharing agreement between NGNA and its subsidiaries. To the extent that the consolidated return group settles cash differently than the amount reported as realized under the benefit-for-loss allocation, the difference is accounted for as either a capital contribution or as a distribution.

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 consists of collateral paid to the Company's counterparties for outstanding derivative instruments. Special deposits primarily consist of health care claims deposits and deposits held by the New York Independent System Operator

(“NYISO”) and by the ISO New England, Inc. (“ISO-NE”). The Company had restricted cash of $44 million and $41 million and special deposits of $49 million and $149 million at March 31, 2016 and 2015, 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, 2016 or 2015. Emission credits are comprised of sulfur dioxide, nitrogen oxide (“NOx”), and carbon dioxide credits. Emission credits are valued at the lower of weighted average cost or market and are held primarily for consumption or may be sold to third-party purchasers. RECs are stated at cost and used to measure compliance with renewable energy standards. RECs 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.

The Company had materials and supplies of $180 million and $158 million, emission credits of $23 million and $44 million, purchased RECs of $117 million and $46 million, and gas in storage of $161 million and $149 million at March 31, 2016 and 2015, respectively.

Derivative Instruments

The Company uses derivative instruments (including forwards, futures, options, purchase contracts, and swaps) to manage commodity price, interest rate, and foreign currency rate risk. All derivative instruments, except those that qualify for the normal purchase normal sale exception, are recorded in the accompanying consolidated balance sheets at their fair value. Qualifying derivative instruments may be designated as either cash flow hedges or fair value hedges.

The effective portion of the change in fair value of a cash flow hedge is recorded in accumulated other comprehensive income (“AOCI”), net of related tax effects, and the ineffective portion is reported in earnings. For the years ended March 31, 2016 and 2015, the Company recorded ineffectiveness related to cash flow hedges of $0.5 million (loss) and $3 million (loss), respectively. Amounts in AOCI are reclassified into earnings in the same period or periods during which the hedged item affects earnings. The effective portion of the change in the fair value of a fair value hedge is offset in the consolidated statements of income by changes in the hedged item. 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. For activity subject to regulatory accounting, gains and losses on derivative instruments are reflected as regulatory assets or liabilities, to be collected from, or refunded to, customers consistent with the regulatory requirements.

The Company has certain non-trading instruments for the physical purchase of electricity that qualify for the normal purchase normal sale exception and are accounted for upon settlement. If the Company were to determine that a contract no longer qualifies for the normal purchase normal sale exception, then the Company would recognize the fair value of the contract in accordance with the regulatory accounting described above.

The Company's accounting policy is to not offset fair value amounts recognized for derivative instruments 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 instrument 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, derivative instruments, or executory contracts. Power purchase agreements that do not qualify as leases or derivative instruments 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.

Fair Value Measurements

The Company measures derivative instruments, available-for-sale securities, and financial assets for which it has elected the fair value option 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;
- 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; and
- Not categorized: as discussed in Note 2, under "New and Recent Accounting Guidance," certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

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, 2016 and 2015 are as follows:

	Electric		Gas		Common	
	Years Ended March 31,		Years Ended March 31,		Years Ended March 31,	
	2016	2015	**2016**	2015	**2016**	2015
Composite rates	**2.7%**	2.7%	**2.8%**	2.9%	**5.5%**	4.8%
Average service lives	**48 years**	48 years	**46 years**	46 years	**34 years**	35 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 at March 31, 2016 and 2015.

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 for each of the years ended March 31, 2016 and 2015 and AFUDC related to debt of $10 million and $6 million for the years ended March 31, 2016 and 2015, respectively. The average AFUDC rates for the years ended March 31, 2016 and 2015 were 3.3% and 2.7%, respectively.

In addition, approximately $10 million and $2 million of interest was capitalized for construction of non-regulated projects during the years ended March 31, 2016 and 2015, 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, 2016 utilizing both income and market approaches. The Company uses a 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, 2016 or 2015, except as in relation to Clean Line Energy Partners LLC (“Clean Line”) as described in Note 12, “Goodwill.”

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

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 81**	$ 87
Accretion expense	**4**	5
Liabilities settled	**(4)**	(11)
Revisions to present values of estimated cash flows	**13**	-
Balance as of the end of the year	**$ 94**	$ 81

At March 31, 2015, certain of the Company's subsidiaries carried out a revaluation study that resulted in a revaluation in estimated cost related to the asset retirement obligations due to changes in remediation cost and enhanced asset replacement programs. These revaluations resulted in no net impact. At March 31, 2016, certain of the Company's subsidiaries carried out a revaluation study that resulted in a net upward revaluation in estimated costs related to the asset retirement obligations. These increases were due to changes in remediation cost and systematic measurement of these regulatory obligations.

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 2016

The new accounting guidance that was adopted for fiscal year 2016 had no material impact on the results of operations, cash flows, or financial position of the Company.

Presentation of Financial Statements – Balance Sheet Classification of Deferred Taxes

In November 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-17, "Balance Sheet Classification of Deferred Taxes." The new guidance requires that all deferred tax assets and liabilities, along with any related valuation allowance be classified as non-current in the balance sheets; the new guidance does not change the existing requirement of prohibiting the offsetting of deferred tax liabilities from one jurisdiction against deferred tax assets of another jurisdiction. The Company early adopted this guidance, retrospectively, effective April 1, 2015.

Fair Value Measurement – Investments Measured at Net Asset Value ("NAV")

In May 2015, the FASB issued ASU 2015-07, "Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities that Calculate New Asset Value per Share (or its equivalent)." The new guidance requires that the valuation of investments using NAV, as a practical expedient to fair value should be excluded from the fair value hierarchy. The Company early adopted this guidance, retrospectively, effective April 1, 2015.

Accounting Guidance Not Yet Adopted

The Company is currently evaluating the impact of recently issued accounting guidance on the presentation, results of operations, cash flows, and financial position of the Company.

Derivative instruments

In March 2016, the FASB issued ASU 2016-05, "Effect of Derivative Contract Novations on Existing Hedge Accounting Relationship." The new guidance clarifies that a change in the counterparty to a derivative contract, in and of itself, does not require the de-designation of a hedging relationship. However, an entity still needs to evaluate whether it is probable that the counterparty will perform under the contract as part of its ongoing effectiveness assessment for hedge accounting. The new guidance, which can be applied either on a prospective basis or on a modified retrospective basis, is effective for non-public entities for periods beginning after December 15, 2017, with early adoption permitted.

Leases

In February 2016, the FASB issued a new lease accounting standard, ASU 2016-02, "Leases (Topic 842)." The key objective of the new standard is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Lessees will need to recognize a right-of-use asset and a lease liability for virtually all of their leases (other than leases that meet the definition of a short-term lease). For income statement purposes, a dual model has been retained, with leases to be designated as operating leases or finance leases. Expenses will be recognized on a straight-line basis for operating leases, and a front-loaded basis for finance leases. For non-public entities, the new standard is effective for periods beginning after December 15, 2019, with early adoption permitted. The new standard must be adopted using a modified retrospective transition, and provides for certain practical expedients.

Financial Instruments – Classification and Measurement

In January 2016, the FASB issued ASU 2016-01, "Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities." The new guidance principally affects the accounting for equity investments and financial liabilities where the fair value option has been elected, as well as the disclosure requirements for financial instruments. The new guidance is effective for non-public entities for periods beginning after December 15, 2018, with early adoption permitted for periods beginning after December 15, 2017.

Revenue Recognition

In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers – Deferral of the Effective Date." The new standard defers by one year the effective date of ASU 2014-09 "Revenue from Contracts with Customers (Topic 606)." The underlying principle of "Revenue from Contracts with Customers" is that an entity will recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to, in exchange for those goods or services. 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, 2016.

Further, in March 2016, the FASB issued ASU 2016-08, which clarifies the implementation guidance on principal versus agent considerations. In May 2016, the FASB issued ASU 2016-12, providing additional clarity on various aspects of Topic 606, including a) Assessing the Collectibility Criterion and Accounting for Contracts That Do Not Meet the Criteria for Step 1, b) Presentation of Sales Taxes and Other Similar Taxes Collected from Customers, c) Noncash Consideration, d) Contract Modifications at Transition, e) Completed Contracts at Transition, and f) Technical Correction. The effective date and transition requirements for the amendments in these updates are the same as the effective date and transition requirements of ASU 2014-09.

Measurement of Inventory

In July 2015, the FASB issued ASU 2015-11, "Simplifying the Measurement of Inventory." The new guidance requires that inventory be measured at the lower of cost and net realizable value (other than inventory measured using "last-in, first out" and the "retail inventory method"). The new guidance, which must be applied prospectively, is effective for non-public entities for periods beginning after December 15, 2016, with early adoption permitted.

Intangibles – Goodwill and Other – Internal-Use Software, Customer's Accounting for Fees Paid in a Cloud Computing Arrangement

In April 2015, the FASB issued ASU 2015-05 "Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement." The amendments provide guidance to customers about whether a cloud computing arrangement includes a software license. If a cloud computing arrangement includes a software license, then the customer should account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer should account for the arrangement as a service contract. The guidance will not change GAAP for a customer's accounting for service contracts. In addition, all software licenses within the scope of Subtopic 350-40 will be accounted for consistent with other licenses of intangible assets. For non-public entities, the new guidance is effective for annual periods beginning after December 15, 2015, and interim periods in annual periods beginning after December 15, 2016, with early adoption permitted.

Presentation of Financial Statements – Balance Sheet Classification of Debt Issuance Costs

In April 2015, the FASB issued ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs." The new guidance requires that debt issuance costs related to term loans, be presented in the balance sheets as a direct deduction from the carrying value of debt. The new guidance, which requires retrospective application, is effective for fiscal years beginning after December 15, 2015, and interim periods within fiscal years beginning after December 15, 2016, with early adoption permitted.

Consolidation

In February 2015, the FASB issued ASU 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis." The new guidance eliminates entity specific consolidation guidance for limited partnerships. It also revises other aspects of the consolidation analysis, including how kick-out rights, fee arrangements and related parties are assessed. The new guidance, which requires either modified retrospective or full retrospective basis application, is effective for periods beginning after December 15, 2016, with early adoption permitted.

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 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 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.

Financial Statement Revision

During 2016, management determined that certain accounting transactions were not properly recorded in the Company's previously issued consolidated financial statements. The Company has corrected the accounting by revising the prior period consolidated financial statements presented herein, the impacts of which are described below. The Company concluded that the corrections were not material to any prior periods.

During the Company's review, it identified the following errors which required correction:

- Open work orders within capital work in progress that were inappropriately classified as capital instead of expense. A cumulative adjustment of $40 million (net of income taxes) was recorded, of which $25 was recorded as a decrease to opening retained earnings (as of March 31, 2014) and $15 million was recorded as a decrease to net income with the correction recorded within operations and maintenance expense for the year ended March 31, 2015.
- A gas costs deferral for the year ended March 31, 2014 that had not reversed into the subsequent fiscal year. An adjustment of $10 million (net of income taxes) was recorded as a decrease to net income with the correction recorded within purchased gas for the year ended March 31, 2015.
- Other miscellaneous account balances that were improperly recorded in the previously issued financial statements. A cumulative adjustment of $12 million (net of income taxes) was recorded, of which $17 million was recorded as a decrease to opening retained earnings (as of March 31, 2014) and $5 million was recorded as an increase to net income for the year ended March 31, 2015.
- An error in the amount of capital-related accruals included in accounts payable of $21 million as well as the classification of payments on sales/leaseback arrangement of $41 million.

There were also a number of items identified during the preparation of the March 31, 2015 financial statements that were recorded and previously disclosed as out of period adjustments. As part of the current year revision, these out of period adjustments were also corrected and recorded. These relate to:

- A correction of the methodology for accruing property taxes for certain subsidiaries, which were previously accrued on a calendar year basis. An adjustment of $51 million (net of income taxes) was recorded as an increase to opening retained earnings (as of March 31, 2014) and a decrease to net income with the correction recorded within other taxes for the year ended March 31, 2015.
- A $45 million (net of income taxes) correction for errors in the deferrals associated with various regulatory assets and liabilities (primarily related to RDM, Net Utility Plant Tracker, and Electric Supply Reconciliation Mechanism).

This was recorded as a decrease to opening retained earnings (as of March 31, 2014) and an increase to net income with the correction recorded within operating revenues for the year ended March 31, 2015.

- Various adjustments to the Company's tax provision (primarily related to the correction of the tax accounting for employee variable pay tax deduction, the transfer of Narragansett pension tracker amounts from AOCI to non-current regulatory assets during the year ended March 31, 2013, and the accounting related to a settlement with the New York State Department of Taxation and Finance's examination of the Company's corporate income tax returns for the years ended December 31, 2000 through 2002). A cumulative adjustment of $8 million was recorded, of which $28 million was recorded as an increase to opening retained earnings (as of March 31, 2014) and $20 million was recorded as a decrease to net income for the year ended March 31, 2015.

These errors, in conjunction with the impact of the aforementioned items, resulted in an understatement in net cash provided by operating activities of $32 million, an overstatement in net cash used in investing activities of $7 million, an understatement in net cash used in financing activities of $41 million, and an understatement in net cashflow from discontinued operations - operating of $2 million for the year ended March 31, 2015.

The following table shows the amounts previously reported as revised:

	As Previously Reported [1]	Adjustments	As Revised
		(in millions of dollars)	
Consolidated Statement of Income	**March 2015**		**March 2015**
Operating revenues	$ 12,361	$ 79	$ 12,440
Operating expenses	11,234	129	11,363
Operating income	1,127	(50)	1,077
Total other deductions, net	(509)	4	(505)
Income before income taxes	618	(46)	572
Income tax expense	201	(1)	200
Income from discontinued operations, net of taxes	12	(2)	10
Net income	447	(47)	400
Consolidated Statement of Cash Flows	**March 2015**		**March 2015**
Net cash provided by operating activities	$ 2,151	$ 32	$ 2,183
Net cash used in investing activities	(2,612)	7	(2,605)
Net cash provided by financing activities	(756)	(41)	(797)
Net cashflow from discontinued operations - operating	96	2	98

	As Previously Reported [1]	Adjustments	As Revised
		(in millions of dollars)	
Consolidated Balance Sheet	**March 2015**		**March 2015**
Total current assets	$ 4,910	$ (17)	$ 4,893
Property, plant and equipment, net	25,671	(76)	25,595
Total other non-current assets	13,093	(17)	13,076
Total assets	43,674	(110)	43,564
Total current liabilities	5,556	(3)	5,553
Total other non-current liabilities	13,672	(52)	13,620
Total liabilities	19,228	(55)	19,173
Retained Earnings			
March 31, 2015	2,915	(55)	2,860
March 31, 2014	2,468	(8)	2,460
Shareholders' equity			
March 31, 2015	16,232	(55)	16,177
March 31, 2014	16,000	(8)	15,992

[1] During 2016, the Company early adopted ASU 2015-17 “Balance Sheet Classification of Deferred Taxes” retrospectively (as discussed in Note 11, “Income Taxes”). This change in accounting policy resulted in the reclassification of balances reported at March 31, 2015.

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,	
	2016	2015
	(in millions of dollars)	
Regulatory assets		
Current:		
Derivative instruments	**$ 120**	$ 113
Energy efficiency	**59**	55
Gas costs adjustment	**121**	120
Rate adjustment mechanisms	**119**	87
Renewable energy certificates	**77**	120
Revenue decoupling mechanism	**131**	72
Transmission service	**57**	63
Other	**28**	26
Total	**712**	656
Non-current:		
Environmental response costs	**1,711**	1,732
Postretirement benefits	**1,980**	2,063
Storm costs	**307**	327
Other	**852**	781
Total	**4,850**	4,903
Regulatory liabilities		
Current:		
Energy efficiency	**195**	128
Gas costs adjustment	**86**	77
Profit sharing	**54**	46
Rate adjustment mechanisms	**146**	179
Revenue decoupling mechanism	**62**	119
Temporary state assessment	**9**	46
Other	**17**	36
Total	**569**	631
Non-current:		
Carrying charges	**169**	139
Cost of removal	**1,702**	1,683
Environmental response costs	**195**	145
Postretirement benefits	**112**	145
Other	**842**	749
Total	**3,020**	2,861
Net regulatory assets	**$ 1,973**	$ 2,067

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.

Derivative instruments: The Company evaluates open derivative instruments for regulatory deferral by determining if they are probable of recovery from, or refund to, customers through future rates. Derivative instruments that qualify for recovery 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 charges and the costs of the Company's 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 is 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 regulatory asset 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 regulatory liability 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, 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 sheets will be refunded to customers over the next year.

Rate adjustment mechanisms: The Company is 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 and actual revenue. Any difference between the allowed revenue and the actual revenue 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, 2016, 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 instruments, cost of removal, environmental response costs, RECs, 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 original term of the rate plan was from April 1, 2013 through March 31, 2016, and provided for electric delivery rate revenue 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 provided for gas delivery rate revenue of $307.4 million in the first year, $314.7 million in the second year, and $322 million in the third year. On December 21, 2015, Niagara Mohawk filed a Petition with the NYPSC seeking authorization to recover approximately $150 million in revenue requirements associated with a proposed two-year, $1.4 billion capital spending program for Niagara Mohawk's electric and gas operations in fiscal years 2017 and 2018. The Petition proposed that the revenue requirement be fully funded by existing regulatory deferrals and proposed no increase in customer rates. The Petition also proposed on extension of the existing rate plan which expired in March 2016 through March 2018.

On May 19, 2016, the NYPSC granted approval of the capital investment petition, approving a two-year capital program worth approximately $1.3 billion and funding of the incremental portion of that investment through the use of $140 million in regulatory liabilities due to customers over 24 months.

Transmission Return on Equity ("ROE") Complaint

On September 11, 2012, the New York Association of Public Power ("NYAPP") filed a complaint against Niagara Mohawk, 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 Niagara Mohawk's ROE to 9.25% including the NYISO participation adder. The MEUA also challenges certain aspects of Niagara Mohawk's transmission formula rate. On February 6, 2014, the NYAPP filed a further complaint against Niagara

Mohawk seeking an order effective February 6, 2014 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 6.6%. On September 8, 2014, the FERC issued orders consolidating the first and second complaints and setting the consolidated complaints and the third complaint for hearing and settlement procedures.

On February 24, 2015, Niagara Mohawk filed an Offer of Settlement and Settlement Agreement ("Settlement") resolving all issues in the complaints and setting the ROE at 10.3%, inclusive of any incentive adders, effective November 2, 2012. The Settlement also provided for various refunds, and separate payments of $200,000 and $180,000 to certain customers. On May 13, 2015, the FERC approved the Offer of Settlement, and on June 12, 2015, Niagara Mohawk filed tariff revisions to implement the new 10.3% ROE negotiated in the settlement. Niagara Mohawk subsequently provided all refunds required by the Settlement and on September 30, 2015 filed a Refund Report with the FERC which concluded this FERC proceeding.

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 Reliability Support Services ("RSS") costs under two agreements with NRG Energy Inc. 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 Niagara Mohawk'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 Niagara Mohawk'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. The parties agreed to the terms of a settlement which was filed with the settlement judge on September 11, 2015 and certified by the settlement judge to the FERC on October 19, 2015. Under the terms of the settlement, Niagara Mohawk will include the costs of the Dunkirk RSS agreements, including the costs associated with extending the 2013 Dunkirk RSS agreement through the end of 2015, less $35 million, in the TSC Rate. The $35 million reduction to the revenue requirement impact of the Dunkirk RSS agreements will be implemented through a billing adjustment included in Niagara Mohawk's 2016 annual TSC informational update filing. Any change in revenues received from wholesale transmission customers resulting from the settlement agreement will be offset by revenues from retail electric distribution customers through the Transmission Revenue Adjustment Clause mechanism.

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 report in October 2014. The audit findings found that the Company's operations 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 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, NGUSA's New York gas businesses 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. On April 20, 2016, the NYPSC released Overland's audit report publicly and adopted the majority of recommendations in the report. The audit report found that the Company, in general, is meeting its obligations to supply self-reported data. The report contains recommendations to improve internal controls and allow for greater consistency in reporting among the New York utilities. The recommendations do not affect current rate case performance targets or mechanisms and may be considered for potential implementation in future rate plans. The Company filed its plan to implement the audit recommendations with the NYPSC on May 19, 2016. On May 26, 2016, the NYPSC issued a Notice Seeking Comments on the draft customer service recommendations that were not addressed in the previous order. The Company filed comments on the draft recommendations on July 20, 2016.

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 and the New York Gas Companies. 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, the Company 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, Niagara Mohawk filed petitions seeking authorization to defer $14.1 million related to a pension settlement loss incurred during the year ending March 31, 2014.

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 decreased from 9.8% to 9.4%, and (iii) the common equity ratio in the capital structure increased from 45% to 48%.

Rate Case Filing

On January 29, 2016, the New York Gas Companies filed to adjust its base gas rates, which, if adopted, would be effective from January 1, 2017. The filing seeks to increase gas delivery base revenues. On June 17, 2016, the New York Gas Companies filed for a month-extension in the suspension period in the proceedings with a make whole provision, such that new rates would become effective February 1, 2017. On July 21, 2016, to allow additional time for the parties to conduct settlement discussions and finalize a joint proposal, the New York Gas Companies requested an additional one-month extension in the suspension period, subject to a make whole, such that new rates would become effective no later than March 1, 2017.

On September 7, 2016, the New York Gas Companies filed a Joint Proposal establishing a three year rate plan beginning January 1, 2017 and ending December 31, 2019. The Joint Proposal is supported by several parties, including Department of Public Service Staff and the City of New York. It is expected that the NYPSC will issue an order on the Joint Proposal in December or January and that new rates would go into effect in either January or February. The Joint Proposal includes a make whole provision that, if approved, is designed to ensure the New York Gas Companies are restored to the same financial position by December 31, 2017 as if new rates went into effect beginning January 1, 2017.

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.

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. 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 establishes a $24.7 million regulatory liability.

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. Brooklyn Union requested a modification to the Capital Reconciliation Mechanism to extend the reconciliation period for two years (calendar years 2015 and 2016) to complete more capital projects and facilitate Brooklyn Union's plan to invest in its distribution system infrastructure. On October 19, 2015, the NYPSC issued an order granting the requested two year extension to the reconciliation period.

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

Electric Rate Case Filing

On November 6, 2015, the Massachusetts Electric Companies filed a one-year rate plan, requesting an increase in base distribution revenue of approximately $211.3 million to take effect from October 1, 2016, which was updated to $205.5 million on April 29, 2016, $202.8 million on June 3, 2016, and $201.9 million on July 25, 2016. The updated rate case filing requests an annualized net increase in distribution revenue of approximately $133.2 million. Approximately $28 million of the increase is associated with higher personal property taxes, and $10 million of the increase to increase funding to the Massachusetts Electric Companies' Storm Contingency Fund to more adequately address mobilization and restoration activities incurred in connection with responding to significant weather events experienced by the Massachusetts Electric Companies since their last rate case in 2009. The increase also reflects the impact of net plant additions since December 31, 2008, the end of the test year in the Massachusetts Electric Companies' last general rate case, as well as its investment in five solar generating facilities placed into service since that time; however, the Massachusetts Electric Companies have been recovering a portion of their investments through recovery mechanisms outside of base distribution rates, and such recovery shall end when recovery commences through base distribution rates, as approved by the DPU. The Massachusetts Electric Companies have also requested revisions to their capital investment recovery mechanism to better align the eligible capital investment with its recent and future plans for capital investment in its distribution system to ensure safe and reliable service to its customers. The Company cannot currently predict the outcome of this case.

2009 Capital Investment 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 1 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 Office of the Attorney General ("Attorney General"), for an independent audit of Massachusetts Electric Companies' 2009 capital investments which, in part, formed the basis for the Massachusetts Electric Companies' RDM rate. The auditor issued its Final Audit Report on August 5, 2015, certifying that the CapEx filing and supporting documentation demonstrated that the costs requested for recovery were supported by source documents and were properly allocable to the Massachusetts Electric Companies. On February 28, 2016, the DPU issued an order generally accepting the auditor's audit report and certification and directing the Massachusetts Electric Companies to implement the following recommendations: (1) perform a review of work orders on equipment energized in 2008 but recorded as in-service in 2009 for accounting purposes; (2) develop a detailed written policy describing the process of data extraction, the categorizing of projects, and any other steps used in producing the CapEx filing, including documentation of key controls, checkpoints and approvals; and (3) eliminate the lag time between energizing equipment and recording it in the Massachusetts Electric Companies' accounting system as in-service and to correct the Massachusetts Electric Companies' accounts for errors associated with manual adjustments associated with in-service dates of assets. The Massachusetts Electric Companies have completed the first recommendation and are currently on track to implement the remaining recommendations by January 2017.

Storm Management Audit

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 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 to respond to and 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. The deferred incremental storm cost and carrying cost amounts have been reduced to reflect the impact of actual and estimated billings to Verizon for vegetation management costs as a result of the DPU's order regarding the December 2008 ice storm. On May 3, 2013, following a request by the Massachusetts Electric Companies for accelerated funding for the Massachusetts Electric Companies' Storm Contingency Fund, the DPU approved a Storm Fund Replenishment Factor ("SFRF") of $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 their storm costs for DPU review and approval. The first filing for $128 million of costs relating to qualifying storms that occurred during calendar years 2010 and 2011 was made on May 31, 2013 (later updated to exclude vegetation management costs billed to Verizon) and the second filing for $94 million of storm costs (net of vegetation management costs billable to Verizon) related to storm events that occurred during calendar year 2012 through March 2013 was made on September 30, 2014. In its September 30, 2014 filing, the Massachusetts Electric Companies also requested an extension of the SFRF through June 2018 to eliminate the deficit in the Storm Contingency Fund created by storm events experienced through March 2013. On April 13, 2016, the DPU extended the SFRF for three additional months until August 4, 2016, unless otherwise ordered, while its prudency review is ongoing. The Company 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 they have been recovering annually with the $40 million of SFRF 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. Massachusetts Electric Companies proposed to credit the Storm Contingency Fund for the $1.6 million balance, which the DPU approved on March 11, 2015.

As part of the November 2015 Electric Rate Case Filing, the Massachusetts Electric Companies proposed a further extension of the approximately $47 million in total SFRF recoveries to August 2019, or fourteen months beyond the June 2018 date proposed in the pending storm cost proceeding.

Gas Transportation and Storage Contracts

On January 15, 2016, the Massachusetts Electric Companies filed petitions with the DPU for approval of: (1) two long-term gas transportation and storage services agreements with Algonquin Gas Transmission, LLC on the proposed Access Northeast pipeline (together, the "ANE Contracts"); (2) two long-term transportation agreements with Tennessee Gas Pipeline, LLC on the proposed Northeast Energy Direct pipeline (together, the "NED Contracts"); (3) an Electric Reliability Service Program ("ERSP") to set parameters for the release of capacity and sale of LNG supply available by virtue of the ANE and NED Contracts; and (4) Long-Term Gas Transportation and Storage Contracts tariffs, which would allow for recovery of the costs associated with the agreements executed by the Massachusetts Electric Companies for the provision of interstate pipeline transportation and gas storage services to electric generation facilities in the region, as well as an innovation incentive for the Massachusetts Electric Companies equal to 2.75% of the annual fixed contract payments under the proposed ANE and NED Contracts. Both pipelines are designed to provide increased natural gas deliverability to the New England markets. If approved by the DPU, the Massachusetts Electric Companies would release their capacity on these pipelines to the electric market in accordance with an Electric Reliability Service tariff, which is subject to approval by the FERC, and in accordance with the state-approved ERSP, in order to improve the reliability and cost of electric supply for its electric retail customers. As a result of receiving an April 21, 2016 termination notice on the NED Contracts from Tennessee Gas Pipeline, LLC, on April 26, 2016, the Massachusetts Electric Companies submitted a motion to withdraw their request for DPU approval of the NED Contracts, which the DPU granted on April 27, 2016. The estimated estimates levelized annual net benefits from the ANE project by itself are $1.1 billion per year from 2019 through 2038 for electric customers in New England under normal weather conditions. There will be DPU hearings on the contracts, with a decision expected by the fall of 2016.

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.

Gas System Enhancement Plan

On April 30, 2015 and April 29, 2016, the DPU approved the Massachusetts Gas Companies' 2015 and 2016 Gas System Enhancement Plans (''GSEP'') for calendar year 2015 and 2016, respectively, and the associated gas system enhancement adjustment 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 Massachusetts 2014 Gas Leaks Act. This program replaced the Targeted Infrastructure Replacement ("TIR") Program in 2015, however recovery of the revenue requirement TIR Program investment will continue until recovery commences through new base distribution rates. The approved GSEAFs are designed to recover from all firm sales and transportation customers a revenue requirement of approximately $28.9 million and $9.7 million for 2016 and 2015, respectively. Also on April 29, 2016, the Massachusetts Electric Companies submitted their first GSEP reconciliation filing for 2015, which reconciled the 2015 revenue requirement on 2015 actual GSEP capital investment with revenue billed through the GSEAFs, and proposed to credit customers $3.3 million as a result of this reconciliation effective November 1, 2016.

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 a ROE of approximately 11% on stranded cost recovery. NEP will recover its remaining non-nuclear stranded costs through 2020. See the "Decommissioning Nuclear Units" section 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. Starting on October 16, 2014, the FERC issued a series of orders as the result of three ROE complaint cases (see the "FERC ROE Complaints" section 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%.

Recovery of Transmission Costs

In conformance with the terms of NEP's Tariff No. 1, on November 17, 2014, NEP submitted a filing to the FERC under Section 205 of the Federal Power Act ("FPA") proposing to reduce the ROE under its Tariff No. 1 formula rates so that they were consistent with those applied under the ISO-NE Open Access Transmission Tariff pursuant to the FERC's Opinion Nos. 531 and 531-A. Under the integrated facilities provisions of Tariff No. 1, NEP supports the cost of transmission facilities owned by its distribution affiliates, Massachusetts Electric and Narragansett, and makes these facilities available for open access transmission service on an integrated basis. The FERC rejected NEP's filing on April 16, 2015, finding that it was inconsistent with the FERC's clarifications issued in its Order on Rehearing in Opinion No. 531-B (see the "FERC ROE Complaints" section in Note 13, "Commitments and Contingencies"). On January 21, 2016, NEP re-filed proposed amendments to its Tariff No. 1 formula rates for integrated facilities to be consistent with Opinion No.531-B among other proposed changes. On March 8, 2016, the FERC accepted the filing approving an effective date of October 16, 2014 for the ROE components. NEP has reduced its compensation to its distribution affiliates in accordance with the Order.

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 project, pursuant to the FERC's Transmission Pricing Policy Order No. 679. NEEWS consists of a series of inter-related transmission upgrades identified in the New England Regional System Plan and is being undertaken to address a number of reliability problems in Connecticut, Massachusetts, and Rhode Island. Effective November 18, 2008, the FERC granted (1) an incentive ROE of 12.89% (125 basis points above the approved base ROE of 11.64%), (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

The RIPUC approved a settlement agreement among the Division, 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%, effective February 1, 2013. The settlement 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,	
	2016	2015
	(in millions of dollars)	
Plant and machinery	**$ 30,890**	$ 28,980
Property held for future use	**15**	15
Land and buildings	**2,227**	2,108
Assets in construction	**1,477**	1,513
Software and other intangibles	**991**	792
Total property, plant and equipment	**35,600**	33,408
Accumulated depreciation and amortization	**(8,136)**	(7,813)
Property, plant and equipment, net	**$ 27,464**	$ 25,595

6. DERIVATIVE INSTRUMENTS AND HEDGING

The Company utilizes derivative instruments to manage commodity price, interest rate and foreign currency rate risk associated with its natural gas and electricity purchases and previously its Euro Medium Term Note 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 instruments measured in dekatherms ("dths") and megawatt hours ("mwhs") are as follows:

	Electric		Gas	
	March 31,		March 31,	
	2016	2015	**2016**	2015
	(in millions)		*(in millions)*	
Gas future contracts (dths)	**-**	-	**14**	20
Gas option contracts (dths)	**-**	-	**16**	4
Gas purchase contracts (dths)	**-**	-	**44**	55
Gas swap contracts (dths)	**-**	-	**76**	65
Electric swap contracts (mwhs)	**12**	11	**-**	-
Total	**12**	11	**150**	144

Amounts Recognized in the Accompanying Consolidated Balance Sheets

	Asset Derivatives March 31, 2016	Asset Derivatives March 31, 2015		Liability Derivatives March 31, 2016	Liability Derivatives March 31, 2015
	(in millions of dollars)			(in millions of dollars)	
Current assets:			Current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas future contracts	**$ 1**	$ -	Gas future contracts	**$ 12**	$ 11
Gas purchase contracts	**1**	14	Gas purchase contracts	**2**	6
Gas swap contracts	**5**	2	Gas swap contracts	**16**	37
Electric option contracts	**-**	-	Electric option contracts	**-**	1
Electric swap contracts	**2**	19	Electric swap contracts	**63**	47
Contracts not subject to rate recovery:			Contracts not subject to rate recovery:		
Gas swap contracts	**-**	-	Gas swap contracts	**-**	1
Hedge contracts:			Hedge contracts:		
Cross-currency & interest rate swaps	**-**	2	Cross-currency & interest rate swaps	**-**	159
Foreign exchange forward contracts	**6**	-	Foreign exchange forward contracts	**1**	-
	15	37		**94**	262
Other non-current assets:			Other non-current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas future contracts	**-**	-	Gas future contracts	**2**	6
Gas purchase contracts	**2**	15	Gas purchase contracts	**-**	1
Gas swap contracts	**-**	-	Gas swap contracts	**2**	3
Electric capacity contracts	**3**	-	Electric capacity contracts	**-**	-
Electric option contracts	**-**	-	Electric option contracts	**1**	-
Electric swap contracts	**-**	-	Electric swap contracts	**36**	29
	5	15		**41**	39
Total	**$ 20**	$ 52	Total	**$ 135**	$ 301

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 rate and foreign currency rate 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 clearing houses act as the counterparty to each trade. Transactions on the NYMEX must adhere to comprehensive collateral and margining requirements. As a result, transactions on the NYMEX are significantly collateralized and have limited counterparty credit risk.

The credit policy for commodity transactions is managed and monitored by the Finance Committee to National Grid plc's Board of Directors ("Finance Committee"), which is responsible for approving risk management policies and objectives for risk assessment, control and valuation, and the monitoring and reporting of risk exposures. NGUSA's 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 EPRMC is chaired by the Vice President of U.S. Treasury and reports to both the NGUSA Board of Directors and the Finance Committee.

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 instruments, 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 $83.6 million and $54 million as of March 31, 2016 and 2015, respectively.

The aggregate fair value of the Company's commodity derivative instruments with credit-risk-related contingent features that are in a liability position at March 31, 2016 and 2015 was $111.8 million and $98.3 million, respectively. The Company had $29 million and $12.1 million collateral posted for these instruments at March 31, 2016 and 2015, respectively. At March 31, 2016, if the Company's credit rating were to be downgraded by one, two, or three levels, it would be required to post additional collateral to its counterparties of $9.6 million, $22.1 million, or $84.5 million, respectively. At March 31, 2015, if the Company's credit rating were to be downgraded by one, two, or three levels, it would be required to post additional collateral to its counterparties of $13.6 million, $23.6 million, or $96.5 million, 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.

As the Company no longer holds any 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 collateral.

Offsetting Information for Derivative Instruments Subject to Master Netting Arrangements

March 31, 2016
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 instruments						
Gas future contracts	$ 1	$ -	$ 1	$ -	$ 1	$ -
Gas purchase contracts	3	-	3	-	-	3
Gas swap contracts	5	-	5	-	-	5
Electric capacity contracts	3	-	3	-	-	3
Electric swap contracts	2	-	2	-	-	2
Foreign exchange forward contracts	6	-	6	-	-	6
Total	$ 20	$ -	$ 20	$ -	$ 1	$ 19

LIABILITIES:	Gross amounts of recognized liabilities *A*	Gross amounts offset in the Consolidated Balance Sheets *B*	Net amounts of liabilities presented in the Consolidated Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral paid *Db*	Net amount *E=C-D*
Derivative instruments						
Gas future contracts	$ 14	$ -	$ 14	$ -	$ 14	$ -
Gas purchase contracts	2	-	2	-	-	2
Gas swap contracts	18	-	18	-	-	18
Electric option contracts	1	-	1	-	-	1
Electric swap contracts	99	-	99	-	29	70
Foreign exchange forward contracts	1	-	1	-	-	1
Total	$ 135	$ -	$ 135	$ -	$ 43	$ 92

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 instruments						
Gas purchase contracts	$ 29	$ -	$ 29	$ -	$ -	$ 29
Gas swap contracts	2	-	2	-	-	2
Electric swap contracts	19	-	19	-	-	19
Cross-currency & interest rate swaps	2	-	2	-	-	2
Total	$ 52	$ -	$ 52	$ -	$ -	$ 52

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 instruments						
Gas future contracts	$ 17	$ -	$ 17	$ -	$ 17	$ -
Gas purchase contracts	7	-	7	-	-	7
Gas swap contracts	41	-	41	-	-	41
Electric option contracts	1	-	1	-	-	1
Electric swap contracts	76	-	76	-	12	64
Cross-currency & interest rate swaps	159	-	159	-	115	44
Total	$ 301	$ -	$ 301	$ -	$ 144	$ 157

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, 2016 and 2015:

	March 31, 2016			
	Level 1	Level 2	Level 3	Total
	(in millions of dollars)			
Assets:				
Derivative instruments				
Gas future contracts	$ 1	$ -	$ -	$ 1
Gas purchase contracts	-	-	3	3
Gas swap contracts	-	5	-	5
Electric capacity contracts	-	-	3	3
Electric swap contracts	-	2	-	2
Foreign exchange forward contracts	-	6	-	6
Investment in Dominion Midstream Partners, LP	-	202	-	202
Available-for-sale securities	128	133	-	261
Total	129	348	6	483
Liabilities:				
Derivative instruments				
Gas future contracts	14	-	-	14
Gas purchase contracts	-	-	2	2
Gas swap contracts	-	18	-	18
Electric option contracts	-	-	1	1
Electric swap contracts	-	99	-	99
Foreign exchange forward contracts	-	1	-	1
Total	14	118	3	135
Net assets	$ 115	$ 230	$ 3	$ 348

	March 31, 2015			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative instruments				
Gas purchase contracts	$ -	$ -	$ 29	$ 29
Gas swap contracts	-	2	-	2
Electric swap contracts	-	19	-	19
Cross-currency & interest rate swaps	-	2	-	2
Available-for-sale securities	125	133	-	258
Total	125	156	29	310
Liabilities:				
Derivative instruments				
Gas future contracts	17	-	-	17
Gas purchase contracts	-	-	7	7
Gas swap contracts	-	41	-	41
Electric options contracts	-	-	1	1
Electric swap contracts	-	76	-	76
Cross-currency & interest rate swaps	-	159	-	159
Total	17	276	8	301
Net assets (liabilities)	$ 108	$ (120)	$ 21	$ 9

Derivative instruments: The Company's Level 1 fair value derivative instruments 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 derivative instruments (e.g. natural gas futures traded on the NYMEX).

The Company's Level 2 fair value derivative instruments primarily consist of over-the-counter ("OTC") interest and currency swap transactions, and gas swap contracts with pricing inputs obtained from the NYMEX 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 instruments. 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 instruments 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 instruments categorized in Level 2 and Level 3.

Available-for-sale securities: Available-for-sale securities are included in financial investments 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).

Investment in Dominion Midstream Partners, LP: The Company's Level 2 Investment in DM is valued based on Level 1 quoted market prices for DM common units, combined with a discount to the quoted market price which is calculated using Level 2 inputs, to reflect restrictions on the transfer of the units and resulting lack of marketability.

Changes in Level 3 Derivative Instruments

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 21**	$ (6)
Transfers out of Level 3	**-**	5
Total gains or losses included in regulatory assets and liabilities	**(25)**	(17)
Settlements	**7**	39
Balance as of the end of the year	**$ 3**	$ 21
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, 2016 or 2015.

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 derivative instruments 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.

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, 2016			Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)	Total			
		(in millions of dollars)					
Gas	Option contracts	$ -	$ (1)	$ (1)	Discounted Cash Flow	Forward Curve Implied Volatility	$0.09-$0.36/dth 34%-38%
Gas	Purchase contracts	-	(1)	(1)	Discounted Cash Flow	Forward Curve LNG Forward Curve	$1.89/dth
Gas	Cross commodity contracts	3	-	3	Discounted Cash Flow	Forward Curve	$10.48-$271.84/dth
Electric	Option contracts	-	(1)	(1)	Discounted Cash Flow	Implied Volatility	12%-54%
Electric	Capacity contracts	3	-	3	Discounted Cash Flow	Forward Curve	$0.58-$5.80/MW
	Total	$ 6	$ (3)	$ 3			

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	Purchase contracts	24	(7)	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	$ 29	$ (8)	$ 21			

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 derivative instruments are forward commodity prices (both gas and electric), implied volatility, and valuation assumptions pertaining to peaking gas deals based on 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, 2016 and 2015 was $10.2 billion.

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 (the "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 substantially all 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 to certain eligible 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 $316 million to the Pension Plans during the year ending March 31, 2017.

PBOP Plans

The Company's 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 $342 million to the PBOP Plans during the year ending March 31, 2017.

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 $46 million and $41 million were expensed in the years ended March 31, 2016 and 2015, respectively.

Components of Net Periodic Benefit Costs

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2016	2015	**2016**	2015
	(in millions of dollars)			
Service cost	**$ 136**	$ 119	**$ 77**	$ 62
Interest cost	**355**	368	**198**	203
Expected return on plan assets	**(448)**	(473)	**(185)**	(190)
Amortization of prior service cost (credit), net	**7**	7	**(5)**	6
Amortization of net actuarial loss	**295**	237	**103**	61
Total cost	**$ 345**	$ 258	**$ 188**	$ 142

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,	
	2016	2015	**2016**	2015
	(in millions of dollars)			
Net actuarial loss (gain)	**$ 261**	$ 793	**$ (34)**	$ 563
Prior service cost	**-**	2	**-**	-
Amortization of net actuarial gain	**(295)**	(237)	**(103)**	(61)
Amortization of prior service (cost) credit, net	**(7)**	(7)	**5**	(6)
Total	**$ (41)**	$ 551	**$ (132)**	$ 496
Included in regulatory assets	**$ (20)**	$ 261	**$ (81)**	$ 380
Included in AOCI	**(21)**	290	**(51)**	116
Total	**$ (41)**	$ 551	**$ (132)**	$ 496

The Company's regulated subsidiaries have regulatory recovery of these obligations and therefore amounts are included in regulatory assets in the accompanying consolidated balance sheets. Costs of non-regulated subsidiaries are recorded as part of AOCI in the accompanying consolidated balance sheets.

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,	
	2016	2015	**2016**	2015
	(in millions of dollars)			
Net actuarial loss	**$ 2,203**	$ 2,237	**$ 1,009**	$ 1,146
Prior service cost (credit)	**34**	41	**(24)**	(29)
Total	**$ 2,237**	$ 2,278	**$ 985**	$ 1,117
Included in regulatory assets	**$ 1,127**	$ 1,147	**$ 697**	$ 777
Included in AOCI	**1,110**	1,131	**288**	340
Total	**$ 2,237**	$ 2,278	**$ 985**	$ 1,117

The amount of expected net actuarial loss and prior service credit to be amortized from regulatory assets and AOCI during the year ended March 31, 2017 for the Pension Plans and PBOP Plans is $109 million and $8million, respectively.

Reconciliation of Funded Status to Amount Recognized

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2016	2015	**2016**	2015
	(in millions of dollars)			
Change in benefit obligation:				
Benefit obligation as of the beginning of the year	**$ (8,934)**	$ (7,872)	**$ (5,067)**	$ (4,469)
Service cost	**(136)**	(119)	**(77)**	(62)
Interest cost	**(355)**	(368)	**(198)**	(203)
Net actuarial gain (loss)	**190**	(998)	**279**	(501)
Benefits paid	**457**	425	**211**	197
Settlements/curtailments	**-**	-	**(22)**	-
Other	**-**	(2)	**-**	(29)
Benefit obligation as of the end of the year	**(8,778)**	(8,934)	**(4,874)**	(5,067)
Change in plan assets:				
Fair value of plan assets as of the beginning of the year	**7,502**	7,052	**2,827**	2,702
Actual (loss) return on plan assets	**(3)**	678	**(60)**	128
Company contributions	**341**	197	**170**	194
Benefits paid	**(457)**	(425)	**(211)**	(197)
Fair value of plan assets as of the end of the year	**7,383**	7,502	**2,726**	2,827
Funded status	**$ (1,395)**	$ (1,432)	**$ (2,148)**	$ (2,240)

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, 2016 and 2015. The aggregate ABO balances for the Pension Plans were $8.4 billion and $8.5 billion as of March 31, 2016 and 2015, respectively.

Amounts Recognized in the Accompanying Consolidated Balance Sheets

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2016	2015	**2016**	2015
	(in millions of dollars)			
Non-current assets	**$ 179**	$ 179	**$ 8**	$ 10
Current liabilities	**(23)**	(23)	**(11)**	(16)
Non-current liabilities	**(1,551)**	(1,588)	**(2,145)**	(2,234)
Total	**$ (1,395)**	$ (1,432)	**$ (2,148)**	$ (2,240)

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2016:

(in millions of dollars) Years Ending March 31,	Pension Plans	PBOP Plans
2017	$ 526	$ 197
2018	533	207
2019	535	216
2020	538	226
2021	541	237
Thereafter	2,737	1,325
Total	$ 5,410	$ 2,408

Assumptions Used for Employee Benefits Accounting

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2016	2015	**2016**	2015
Benefit Obligations:				
Discount rate	**4.25%**	4.10%	**4.25%**	4.10%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50%
Expected return on plan assets	**6.25%-6.5%**	6.25%	**6.25%-6.75**	6.25% - 6.75%
Net Periodic Benefit Costs:				
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%

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.

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,	
	2016	2015
Health care cost trend rate assumed for next year		
Pre 65	**7.50%**	8.00%
Post 65	**6.25%**	6.50%
Prescription	**11.00%**	6.50%
Rate to which the cost trend is assumed to decline (ultimate)	**4.50%**	5.00%
Year that rate reaches ultimate trend		
Pre 65	**2025**	2022
Post 65	**2024**	2022
Prescription	**2025**	2022

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

(in millions of dollars)	**March 31, 2016**
1% point increase	
Total of service cost plus interest cost	$ 57
Postretirement benefit obligation	807
1% point decrease	
Total of service cost plus interest cost	(45)
Postretirement benefit obligation	(669)

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, 2016 and 2015 are as follows:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2016	2015	**2016**	2015
U.S. equities	**20%**	20%	**40%**	39%
Global equities (including U.S.)	**7%**	7%	**6%**	6%
Global tactical asset allocation	**10%**	10%	**8%**	9%
Non-U.S. equities	**10%**	10%	**21%**	21%
Fixed income	**40%**	40%	**25%**	25%
Private equity	**5%**	5%	**-**	-
Real estate	**5%**	5%	**-**	-
Infrastructure	**3%**	3%	**-**	-
	100%	100%	**100%**	100%

Fair Value Measurements

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

	March 31, 2016				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in millions of dollars)		
Pension Assets:					
Cash and cash equivalents	$ 13	$ 61	$ -	$ 92	$ 166
Accounts receivable	108	-	-	-	108
Accounts payable	(105)	-	-	-	(105)
Convertible securities	-	1	-	-	1
Equity	939	223	-	1,878	3,040
Global tactical asset allocation	-	-	-	373	373
Fixed income securities	-	2,798	-	138	2,936
Preferred securities	1	23	-	-	24
Futures contracts	-	(2)	-	-	(2)
Private equity	-	-	-	445	445
Real estate	-	-	-	397	397
Total	$ 956	$ 3,104	$ -	$ 3,323	$ 7,383
PBOP Assets:					
Cash and cash equivalents	$ 35	$ 13	$ -	$ 2	$ 50
Accounts receivable	28	-	-	-	28
Accounts payable	(25)	-	-	-	(25)
Equity	423	84	-	1,220	1,727
Global tactical asset allocation	72	-	-	189	261
Fixed income securities	3	675	-	-	678
Futures contracts	-	1	-	-	1
Private equity	-	-	-	6	6
Total	$ 536	$ 773	$ -	$ 1,417	$ 2,726

	March 31, 2015				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in millions of dollars)		
Pension Assets:					
Cash and cash equivalents	$ 19	$ 53	$ -	$ 78	$ 150
Accounts receivable	116	-	-	-	116
Accounts payable	(142)	-	-	-	(142)
Equity	958	229	-	1,923	3,110
Global tactical asset allocation	-	-	-	349	349
Fixed income securities	-	2,955	-	147	3,102
Preferred securities	1	29	-	-	30
Futures contracts	-	4	-	-	4
Private equity	-	-	-	413	413
Real estate	-	-	-	370	370
Total	$ 952	$ 3,270	$ -	$ 3,280	$ 7,502
PBOP Assets:					
Cash and cash equivalents	$ 39	$ 10	$ -	$ 1	$ 50
Accounts receivable	5	-	-	-	5
Accounts payable	(2)	-	-	-	(2)
Equity	446	83	-	1,303	1,832
Global tactical asset allocation	70	-	-	179	249
Fixed income securities	3	683	-	-	686
Private equity	-	-	-	7	7
Total	$ 561	$ 776	$ -	$ 1,490	$ 2,827

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. Cash and cash equivalents invested in the Employee Benefit Temporary Investment Funds and JPMorgan Chase Bank Liquidity Funds are excluded from the fair value hierarchy. 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. 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 NAV per fund share, derived from the underlying securities' quoted prices in active markets, and they are excluded from the fair value hierarchy. Investments in commingled funds with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

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. Those which are open ended mutual funds with observable pricing are classified as Level 1. Investments with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

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. 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 excluded from the fair value hierarchy.

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. Investments in limited partnerships with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

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

Other Benefits

At March 31, 2016 and 2015, the Company had accrued workers compensation, auto, and general insurance claims which have been incurred but not yet reported of $90.7 million and $82.7 million, respectively.

9. ACCUMULATED OTHER COMPREHENSIVE INCOME

The following table represents the changes in the Company's AOCI for the years ended March 31, 2016 and 2015:

	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total
		(in millions of dollars)		
Balance as of March 31, 2014	$ 2	$ (652)	$ (2)	$ (652)
Other comprehensive income (loss) before reclassifications:				
Unrecognized net acturial loss (net of $219 tax benefit)	-	(313)	-	(313)
Gain on investment (net of $9 tax expense)	13	-	-	13
Amounts reclassified from other comprehensive income (loss):				
Amortization of net actuarial loss (net of $52 tax expense) [2]	-	75	-	75
Amortization of treasury lock (net of $1 tax benefit) [1]	-	-	(1)	(1)
Gain on investment (net of $5 tax benefit) [2]	(7)	-	-	(7)
Net current period other comprehensive income (loss)	6	(238)	(1)	(233)
Balance as of March 31, 2015	$ 8	$ (890)	$ (3)	$ (885)
Other comprehensive income (loss) before reclassifications:				
Unrecognized net acturial loss (net of $42 tax benefit)	-	(61)	-	(61)
Gain on investment (net of $1 tax expense)	2	-	-	2
Amounts reclassified from other comprehensive income (loss):				
Amortization of net actuarial loss (net of $71 tax expense) [2]	-	103	-	103
Amortization of treasury lock (net of $0 tax benefit) [1]	-	-	1	1
Gain on investment (net of $4 tax benefit) [2]	(6)	-	-	(6)
Net current period other comprehensive income (loss)	(4)	42	1	39
Balance as of March 31, 2016	**$ 4**	**$ (848)**	**$ (2)**	**$ (846)**

(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.

The Company expects no amount in AOCI related to hedging activity will be reclassified into earnings during the year ended March 31, 2017.

10. CAPITALIZATION

The aggregate maturities of long-term debt for the years subsequent to March 31, 2016 are as follows:

(in millions of dollars) Years Ending March 31,		
2017	$	940
2018		106
2019		54
2020		1,026
2021		346
Thereafter		6,766
Total	$	9,238

Sinking fund repayment requirements related to certain of the Company's Promissory Notes to NGNA and First Mortgage Bonds for the years subsequent to March 31, 2016 are as follows:

(in millions of dollars) Years Ending March 31,		
2017	$	19
2018		19
2019		19
2020		19
2021		19
Thereafter		144
Total	$	239

The Company's debt agreements and banking facilities contain covenants, including those relating to the periodic and timely provision of financial information by the issuing entity and financial covenants such as restrictions on the level of indebtedness. Failure to comply with these covenants, or to obtain waivers of those requirements, could in some cases trigger a right, at the lender's discretion, to require repayment of some of the Company's debt and may restrict the Company's ability to draw upon its facilities or access the capital markets. 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, 2016 and 2015, the Company was in compliance with all such covenants.

Significant Debt Covenants and Facilities

European Medium Term Note Program

The Company previously issued debt instruments ("instruments") under a Euro Medium Term Note program (the "Program") under which it was able to issue instruments up to a total of the equivalent of 4 billion Euros. Such instruments issued under the Program were admitted to trading on the London Stock Exchange. The Program commenced in December 2007 and was renewed annually until December 2015. The non-renewal of the Program precludes the issuance of new instruments under the Program, but does not impact the outstanding debt balances and their maturity dates. As of March 31, 2016, the Company had no outstanding debt balances under the Program.

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"). At March 31, 2016 and 2015, $641 million of GFRB were outstanding; $230 million of which are variable-rate, auction rate bonds. The GFRB currently in auction rate mode 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 auction 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 on long-term debt was not material for the years ended March 31, 2016 or 2015.

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 $49 million, respectively, of non-callable First Mortgage Bonds ("FMB"). These FMB indentures include, among other provisions, limitations on the issuance of long-term debt.

State Authority Financing Bonds

At March 31, 2016, the Company had outstanding $918 million of State Authority Financing Bonds, of which, approximately $495 million were issued through NYSERDA and the remaining $423 million were issued through various other state agencies.

Approximately $429 million of State Authority Financing Bonds were issued to secure a like amount of tax-exempt revenue bonds issued by NYSERDA. These securities bear interest at short-term adjustable interest rates (with an option to convert to other rates, including a fixed interest rate). The bonds are currently in auction rate mode and are backed by bond insurance. These bonds cannot be put back to Niagara Mohawk 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 Niagara Mohawk or the bond insurer, whichever is greater. The effect on interest on long-term debt has not been material in either of the years ended March 31, 2016 or 2015. Additionally, Genco has $41 million of 1999 Series A Pollution Control Revenue Bonds due October 1, 2028. Genco also has outstanding $25 million of variable rate 1997 Series A Electric Facilities Revenue Bonds due December 1, 2027.

Additionally, at March 31, 2016, NEP had outstanding $372 million of Pollution Control Revenue Bonds in tax-exempt commercial paper mode and Nantucket had $51 million of Electric Revenue Bonds in tax exempt commercial paper mode. The Electric Revenue Bonds were issued by the Massachusetts Development Finance Agency in connection with Nantucket's financing of its first and second underground and submarine cable projects. Sinking fund payments of $0.4 million were made during the year ended March 31, 2016.

Standby Bond Purchase Agreement

Two of the Company's subsidiaries have a Standby Bond Purchase Agreement ("SBPA"), which expires on November 20, 2019. This agreement provides liquidity support for $423 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.

Committed Facility Agreements

At March 31, 2016, the Company, NGNA, and the Parent have a committed revolving credit facility of £1.7 billion which matures in May 2021. This facility has not been drawn against. The Company, 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 £1.7 billion limit. The terms of the facility restrict the borrowing of all U.S. subsidiaries of the Company to $25 billion excluding intercompany indebtedness. Additionally, this facility has a number of non-financial covenants which the Company is obliged to meet. At March 31, 2016 and 2015, NGNA and the Parent were in compliance with all covenants.

Commercial Paper and Revolving Credit Agreements

At March 31, 2016, 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 2018 and 2021. At March 31, 2016 and 2015, there were $179 million and $486 million of borrowings outstanding on the U.S. commercial paper program and $119 million and $96 million outstanding on the Euro commercial paper program, respectively.

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.

Significant Debt Issuances and Redemptions

Notes Payable

At March 31, 2016 and 2015 the Company had outstanding $7.3 billion and $6.3 billion, respectively, of unsecured medium and long-term notes with various interest rates and maturity dates. In March 2016, Brooklyn Union issued $500 million of unsecured senior long-term debt at 3.407% with a maturity date of March 10, 2026 and $500 million of unsecured senior long-term debt at 4.504% with a maturity date of March 10, 2046. 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.

Industrial Development Revenue Bonds

At March 31, 2015, 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 fully and unconditionally guaranteed the payment obligations with regard to these tax-exempt bonds. On November 20, 2015, Genco redeemed the $128 million of Industrial Development Revenue Bonds and KeySpan was relieved of all related guarantee obligations.

State Authority Financing Bonds

At March 31, 2015, Niagara Mohawk had outstanding $75 million of 5.15% fixed rate pollution control revenue bonds issued through NYSERDA callable at par. On June 30, 2015, Niagara Mohawk redeemed the bond at par prior to maturity.

Intercompany Loans

On November 20, 2015, Genco entered into multiple intercompany loans with NGNA totaling $227 million, composed of a $165 million intercompany loan with an interest rate of 3.25% due to mature on April 30, 2028 and a $62 million intercompany loan with an interest rate of 3.13% due to mature on June 1, 2027. The intercompany loans have an annual sinking fund requirement totaling $18 million. These intercompany loans are included in long-term debt in the accompanying consolidated balance sheets.

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ 1**	$ (57)
State	**56**	43
Total current tax expense (benefit)	**57**	(14)
Deferred tax expense (benefit):		
Federal	**338**	230
State	**12**	(11)
Total deferred tax expense (benefit)	**350**	219
Amortized investment tax credits [1]	**(5)**	(5)
Total deferred tax expense	**345**	214
Total income tax expense	**$ 402**	$ 200

[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, 2016 and 2015 are 38% and 34.8%, 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,	
	2016	2015
	(in millions of dollars)	
Computed tax	**$ 370**	$ 201
Change in computed taxes resulting from:		
Investment tax credits	**(5)**	(5)
State income tax, net of federal benefit	**45**	20
Other items, net	**(8)**	(16)
Total	**32**	(1)
Total income tax expense	**$ 402**	$ 200

The Company is included in the NGNA and subsidiaries consolidated federal income tax return and Massachusetts and New York unitary state income tax returns. The Company has joint and several liability for any potential assessments against the consolidated group.

During the period there was no material change in the Company's deferred tax liability for the decrease in the tax rate from 7.1% to 6.5% applicable to New York entities beginning with the year ended March 31, 2017. Likewise there was no material change in the Company's deferred tax liability for the increase in the Metropolitan Transportation Authority surcharge from 25.6% to 28%.

On August 26, 2016, the IRS issued Revenue Procedure 2016-48 that enables the Company to claim prior year's unclaimed bonus depreciation in its federal income tax return for the year ended March 31, 2016. The Company does not believe that adoption of this procedure will have a material impact on its results of operations, financial position, or cash flows.

Deferred Tax Components

	March 31,	
	2016	2015
	(in millions of dollars)	
Deferred tax assets:		
Environmental remediation costs	**$ 545**	$ 587
Future federal benefit on state taxes	**171**	159
Net operating losses	**812**	574
Postretirement benefits and other employee benefits	**1,673**	1,728
Regulatory liabilities - other	**590**	543
Other items	**535**	445
Total deferred tax assets [1]	**4,326**	4,036
Deferred tax liabilities:		
Property related differences	**6,803**	6,187
Regulatory assets - environmental response costs	**682**	713
Regulatory assets - postretirement benefits	**718**	729
Regulatory assets - other	**724**	626
Other items	**358**	346
Total deferred tax liabilities	**9,285**	8,601
Net deferred income tax liabilities	**4,959**	4,565
Deferred investment tax credits	**30**	35
Deferred income tax liabilities, net	**$ 4,989**	$ 4,600

[1] The Company established a valuation allowance for deferred tax assets in the amount of $6 million related to expiring charitable contribution carryforwards at March 31, 2016. There was no valuation allowance for deferred tax assets at March 31, 2015.

As a result of retrospective adoption of ASU 2015-17, the Company adjusted its current portion of deferred income tax assets, net and non-current deferred income tax liabilities, net by $242 million as of March 31, 2015.

Net Operating Losses

The following table presents the amounts and expiration dates of net operating losses as of March 31, 2016:

Expiration of net operating losses:	Federal	State of New York	New York City	State of Massachusetts
	(in millions of dollars)			
3/31/2029	$ 198	$ -	$ -	$ -
3/31/2030	78	-	-	-
3/31/2032	114	-	-	-
3/31/2033	535	-	-	-
3/31/2034	573	-	-	9
3/31/2035	504	1,181 (1)	286 (1)	222
3/31/2036	531	327	81	140

(1) The amounts represent net operating losses that were incurred before the tax year ended March 31, 2015 that will be converted into a Prior Net Operating Loss Conversion subtraction that can be utilized beginning with fiscal year 2017.

Unrecognized Tax Benefits

As of March 31, 2016 and 2015, the Company's unrecognized tax benefits totaled $552 million and $522 million, respectively, of which $60 million and $58 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,	
	2016	2015
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 522**	$ 510
Gross increases - tax positions in prior periods	**18**	15
Gross decreases - tax positions in prior periods	**(23)**	(45)
Gross increases - current period tax positions	**35**	47
Settlements with tax authorities	**-**	(5)
Balance as of the end of the year	**$ 552**	$ 522

As of March 31, 2016 and 2015, the Company has accrued for interest related to unrecognized tax benefits of $79 million and $43 million, respectively. During the years ended March 31, 2016 and 2015, the Company recorded interest expense of $36 million and $11 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. During the year ended March 31, 2016 and 2015, the Company recognized tax penalties in the amount of $0.6 million and $0.3 million, respectively.

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, excluding the impact of the potential settlement with the state of New York, the Company does not believe any such increases or decreases would be material to its results of operations, financial position, or cash flows.

The Company is included in NGNA and subsidiaries' administrative appeal with the IRS related to the issues disputed in the examination cycles for the years ended August 24, 2007, March 31, 2008, and March 31, 2009. Pursuant to the Company's tax sharing agreement, the appeals may result in a change to allocated tax. During the period, the IRS commenced its next examination cycle which includes income tax returns for the years ended March 31, 2010 through March 31, 2012. The examination is not expected to conclude until December 2017. The income tax returns for the years ended March 31, 2013 through March 31, 2016 remain subject to examination by the IRS.

The Company is included in NGNA and subsidiaries' appeal with the Massachusetts Department of Revenue ("MADOR") related to issues disputed in examination cycles for the years ended March 31, 2001 through March 31, 2005. In September 2016, the appeal related to examination cycles ended March 2001 through March 2002 was denied. In March 2016, the state of Massachusetts concluded its examination of NGNA and subsidiaries' tax returns for the years ended March 31, 2006 through March 31, 2008. The Company is appealing certain adjustments made by the MADOR disputed in this examination cycle. The income tax returns for the years ended March 31, 2009 through March 31, 2016 remain subject to examination by the state of Massachusetts.

The state of New York is in the process of examining the Company's NYS income tax returns. The following table presents the subsidiaries and years currently under examination. The income tax returns for the subsequent years through March 31, 2016 remain subject to examination by the state of New York.

Companies	Years Under Examination
KeySpan Corporation and Subsidiaries	December 31, 2003 through March 31, 2008
KeySpan Gas East	December 31, 2003 through March 31, 2008
Brooklyn Union	August 24, 2007 through March 31, 2008
National Grid Development Holdings, Inc.	March 31, 2009 through March 31, 2012
National Grid Services, Inc.	March 31, 2009 through March 31, 2012
Genco	March 31, 2009 through March 31, 2012
Niagara Mohawk Holdings, Inc.	March 31, 2009 through March 31, 2012

In August 2015, KeySpan Corporation received a preliminary audit report from the state of New York with a proposed increase to state taxable income primarily related to the interest deductions attributable to subsidiary capital. The Company has established a tax reserve of $8 million, net of federal benefit, related to this audit.

In June 2016, the New York Gas Companies received preliminary audit reports with proposed changes to state taxable income primarily related to transition property depreciation deduction. Brooklyn Union conducted an internal review of the audit report, agreed with its findings, and will enter into settlement discussions with the state of New York in the next fiscal year. KeySpan Gas East had previously established a reserve for uncertain tax position for the years under examination. Within the next twelve months, KeySpan Gas East may adjust the tax reserves following the internal review of the audit report and settlement discussions with the state of New York. The range of the reasonably possible change in recognition of tax benefit is estimated to be between zero and $2 million.

The City of New York is in the process of examining the income tax returns of KeySpan Corporation and Subsidiaries and National Grid Services, Inc. for the years ended December 31, 2003 through December 31, 2005, and March 2012 through March 2014, respectively. The income tax returns for the subsequent years through March 31, 2016 remain subject to examination by the City of New York.

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

Jurisdiction	Tax Year
Federal	March 31, 2010
Massachusetts	March 31, 2009
New York	December 31, 2003
New York City	December 31, 2003

12. GOODWILL

The following table represents the changes in the carrying amount of goodwill for the years ended March 31, 2016 and 2015:

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 7,129**	$ 7,151
Impairment in Clean Line	**-**	(22)
Balance as of the end of the year	**$ 7,129**	$ 7,129

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. 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.

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 was prepared using specific assumptions, rather than the general assumptions used in relation to the Company's longstanding operating companies. The annual impairment test yielded a negative implied fair value of goodwill for the Clean Line reporting unit, and an impairment of $22 million was 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. These 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 steam electric power plants have been required by the DEC pursuant to Section 316 of the Clean Water Act to mitigate the plants' alleged cooling water system impacts to aquatic organisms. Final permits have been issued for Port Jefferson and Northport. Capital improvements have been completed at Port Jefferson and are in the engineering phase for Northport. The Company continues to engage in discussions with the DEC regarding the nature of capital upgrades or other mitigation measures necessary to reduce any impacts at E.F. Barrett. Total capital costs for these improvements at Northport and E.F. Barrett are estimated to be approximately $76 million. Costs associated with these capital improvements are 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, 2016 and 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, 2016 is presently estimated at $1.9 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 net regulatory asset of $1.5 billion on the consolidated balance sheets at March 31, 2016 and 2015.

Expenditures incurred were approximately $115 million and $102 million for the years ended March 31, 2016 and 2015, respectively.

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 $3 million and $1 million for the years ended March 31, 2016 and 2015, respectively. The Company estimated the remaining cost of the environmental remediation activities at non-utility sites were $30 million and $26 million at March 31, 2016 and 2015, respectively. The Company's environmental obligation is discounted at a rate of 6.5%, and the undiscounted amount of environmental liabilities at March 31, 2016 and 2015 was $36 million and $32, 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 estimated, depending on 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. Where the Company has regulatory recovery, it believes 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.

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 $99 million and $97 million for the years ended March 31, 2016 and 2015, respectively.

The future minimum lease payments for the years subsequent to March 31, 2016 are as follows:

(in millions of dollars)		
Years Ending March 31,		
2017	$	98
2018		99
2019		85
2020		60
2021		61
Thereafter		356
Total	$	759

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, which are recoverable from customers. The Company's gas distribution subsidiaries are liable for these payments regardless of the level of service required from third-parties. 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, 2016 are summarized in the table below:

(in millions of dollars) Years Ending March 31,	Energy Purchases	Capital Expenditures
2017	$ 1,538	$ 423
2018	841	76
2019	632	69
2020	498	49
2021	432	38
Thereafter	2,104	-
Total	$ 6,045	$ 655

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, 2016, 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
KeySpan Ravenswood LLC Lease	(i)	$ 315	May 2040
Reservoir Woods	(ii)	196	October 2029
Surety Bonds	(iii)	222	Revolving
Commodity Guarantees and Other	(iv)	98	November 2027 - January 2042
Letters of Credit	(v)	338	May 2016 - February 2017
NY Transco Parent Guaranty	(vi)	842	None
National Grid Algonqin LLC	(vii)	103	December 2021
		$ 2,114	

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

(i) 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, 2016, the Company's obligation related to the lease was $120 million and is reflected in other non-current liabilities in the accompanying consolidated balance sheets.

(ii) The Company has fully and unconditionally guaranteed $196 million in lease payments through 2029 related to the lease of office facilities by its service company at Reservoir Woods in Waltham, Massachusetts.

(iii) 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.

(iv) The Company has guaranteed commodity-related and operational payments for certain subsidiaries. These guarantees are provided to third-parties to facilitate physical and financial transactions supporting the purchase and transportation of natural gas, oil and other petroleum products for gas and electric production and financing activities. The guarantees cover actual transactions by these subsidiaries that are still outstanding as of March 31, 2016.

(v) 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.

(vi) 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.

(vii) In connection with NGUSA's investment in the Access Northeast natural gas pipeline project, the Company has entered into a guarantee of the required capital contributions of NGA, an indirect wholly-owned subsidiary of the Company. The guarantee agreement, which is dated September 14, 2015, commits the Company to serve as a guarantor for up to $103 million of the capital contributions of NGA from the time of the effective date of the guarantee agreement through the earlier of (i) December 31, 2021, or (ii) the time at which NGA's capital commitments have been fully discharged.

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, four agreements were filed with the FERC, in part, for approval to recover the costs associated with the transmission cable and related facilities (the "Project") that will be allocated to the Company and Block Island Power Company through transmission rates. On September 2, 2014, the FERC accepted all four agreements thus approving cost recovery for the Project, with no conditions, that will apply to the Company's costs as well as those of NEP. The agreements went into effect on September 30, 2014. On January 30, 2015, Narragansett closed on its purchase of the Transmission Facilities from Deepwater.

Annual Solicitations

The 2009 Rhode Island law also requires that, beginning on July 1, 2010, the Company conduct four annual solicitations for proposals from renewable energy developers and, provided commercially reasonable proposals have been received, enter into long-term contracts for the purchase of capacity, energy, and attributes from newly developed renewable energy resources. The Company's four solicitations have resulted in four PPAs that have been approved by the RIPUC:

- First Solicitation: On July 28, 2011, the RIPUC approved a 15-year PPA with Orbit Energy Rhode Island, LLC for a 3.2 MW anaerobic digester biogas project.
- Second Solicitation: On May 11, 2012, the RIPUC approved a 15-year PPA with Black Bear Development Holdings, LLC for a 3.9 MW run-of-river hydroelectric plant located in Orono, Maine. The facility reached commercial operation on November 22, 2013.
- Third Solicitation: On October 25, 2013, the RIPUC approved a 15-year PPA with Champlain Wind, LLC for a 48 MW land-based wind project located in Carroll Plantation and Kossuth Township, Maine.
- Fourth Solicitation: On October 29, 2015, the RIPUC approved a 15-year PPA with Copenhagen Wind Farm, LLC for an 80 MW land-based wind project located in Denmark, New York.

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 RECs 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 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 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. On July 18, 2015, the FERC approved an amended tariff compliance filing submitted by the NETOs in response to Opinion No. 531-B. This order constitutes final FERC action on the first ROE complaint. By December 31, 2015, the Company's total refund obligation of approximately $9.2 million for the periods October 1, 2011 through December 31, 2012, and October 16, 2014 through December 31, 2014, was returned to customers, followed by refund compliance reports submitted to the FERC. The NETOs, including the Company, have appealed certain aspects of the FERC's orders in the first ROE complaint to the U.S. Court of Appeals for the DC Circuit. At this time, the Company is unable to predict the outcome of the appeal.

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 expected 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 complainants seeking to lower the base ROE for New England transmission rates to 8.84% effective as of July 31, 2014. On November 24, 2014, the FERC issued an order consolidating this complaint with the second ROE complaint discussed above, setting both matters for investigation and a trial-type, evidentiary hearing on a consolidated basis. The FERC's order established a 15-month refund period for the third ROE complaint beginning on July 31, 2014 and determined that it would be appropriate for the parties to litigate a separate ROE for the two separate refund periods established by each of the complaints. In its order consolidating the complaints and setting them for hearing, the FERC noted that, if the case is fully litigated, the FERC expects to issue its final decision by September 30, 2016. Hearings in this proceeding were held in February 2016. On March 25, 2016, an Administrative Law Judge ("ALJ") released his decision on the second and third ROE complaints. The ALJ found that the NETOs base ROE should be reduced to 9.59% for the first period at issue (December 27, 2012 through March 26, 2014), but the ROE should be increased to 10.90% for the second period (July 31, 2014 through October 30, 2015, and prospectively after the FERC issues an order on this decision). The new ROEs resulting from the second and third ROE complaints will not go into effect until the FERC issues an order addressing the ALJ's decision.

On April 29, 2016, a group of Massachusetts municipal customers filed a fourth ROE complaint at the FERC arguing that the FERC should reduce the NETOs base ROE to 8.61% and should cap the NETOs' total ROE, including any ROE incentives, at 11.24%. On June 3, 2016, the NETOs filed an answer to this complaint. On September 20, 2016, the FERC issued an order setting the fourth ROE complaint for hearing and settlement proceedings.

FERC 206 Proceeding on Rate Transparency

On December 28, 2015, the FERC initiated a proceeding under Section 206 of the FPA. The FERC found that the ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC found that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners ("PTOs"). In addition, the FERC found that the ISO-NE PTOs', including the Company's, current RNS and Local Network Service ("LNS") formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. The FERC explained that the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. Accordingly, the FERC established hearing and settlement judge procedures to develop just and reasonable formula rate protocols to be included in the ISO-NE Tariff and to examine the justness and reasonableness of the RNS and LNS rates. The matter is currently in settlement procedures. At this time, the Company is unable to predict and estimate any impact to earnings.

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 Genco 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.

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 U.S. Department of Energy ("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, 2016			Future Estimated Billings to the Company
Unit	%	Amount	Date Retired	Amount
Yankee Atomic	34.5	$ 512	Feb 1992	$ 5,819
Connecticut Yankee	19.5	331	Dec 1996	17,165
Maine Yankee	24.0	621	Aug 1997	6,528

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 U.S. Court of Appeals for the Federal Circuit 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 U.S. 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, 2016, total net proceeds of $25.6 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 refunds its share to its customers through the CTCs. The remaining amount to be refunded is included within regulatory liabilities in the accompanying consolidated balance sheets.

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. In March 2014, Maine Yankee and Yankee Atomic received 100% of the DOE Phase II proceeds expected ($35.8 million and $73.3 million, respectively). Connecticut Yankee received a partial payment of $90 million of the expected $126.3 million. The balance was received in April 2014.

On April 29, 2014, the Yankees submitted informational filings to the FERC in order to flow through the DOE Phase II Litigation proceeds to their Sponsor companies, including the Company, in accordance with financial analyses that were performed earlier that year and supported by stakeholders from Connecticut, Massachusetts, and Maine. The filings allowed for the flow through of the proceeds to the Sponsors, including the Company, with a rate effective date of June 1, 2014. As of March 31, 2016, total net proceeds of $57.8 million have been refunded to the Company by the Yankees. The Company refunds its share of the net proceeds to its customers through the CTCs.

On August 15, 2013 the Yankees brought further litigation (the "Phase III Litigation") in the Claims Court to recover damages incurred from 2009 through 2012. On March 25, 2016, the judge awarded the Yankees an aggregate of $76.8 million in damages for the Phase III Litigation which is about 98.6% of the damages sought. The DOE elected not to seek appellate review.

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 DC Circuit ("DC Circuit Court") directed the Nuclear Regulatory Commission ("NRC") to resume the Yucca Mountain licensing process despite insufficient funding to complete it. On October 28, 2013, the DC 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, 2016 and 2015, 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.

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,	
	2016	2015	**2016**	2015
	(in millions of dollars)		*(in millions of dollars)*	
National Grid plc	**$ -**	$ -	**$ 44**	$ 52
NGNA	**28**	-	**-**	-
Other	**-**	2	**-**	2
Total	**$ 28**	$ 2	**$ 44**	$ 54

Advances from Affiliates

In August 2009, the Company and KeySpan 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 London Interbank Offered Rate plus 1.4%. At March 31, 2016 and 2015 there were no outstanding advances under this agreement.

In August 2008, the Company entered into an agreement with NGNA, whereby the Company can borrow up to $1.5 billion from time to time for working capital needs. The agreement can be amended and restated from time to time with the latest amendment made in February 2016 to increase the borrowing capacity to $8 billion. These advances do not bear interest. At March 31, 2016 and 2015, the Company had $3.1 billion and $1.1 billion outstanding advances from NGNA under this agreement.

Holding Company Charges

The Company received charges from National Grid Commercial Holdings Limited (an affiliated company in the United Kingdom) 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, 2016 and 2015, the effect on net income was $32 million and $45 million before taxes and $19 million and $27 million after taxes.

16. PREFERRED STOCK

Preferred stock of NGUSA 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 NGUSA subsidiaries at March 31, 2016 and 2015 is as follows:

		Shares Outstanding		Amount		
		March 31,		March 31,		Call
Series	Company	**2016**	2015	**2016**	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 NYS. 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.

Preferred stock of NGUSA

The Company has series A through F non-participating non-callable preferred stock (5,000 total shares authorized, 915 outstanding) which have no fixed redemption date. The series A through F shares rank above all common shares, but below the Company's debt holders in an event of liquidation. If the Company does not pay its annual dividend on the A through F series preferred stock, it is subject to limitations on the payment of any dividends to its common shareholder. The par value of the series A through F preferred stock is $0.10. The fixed rate on the series A through E preferred stock is 6.5%. The fixed rate on the series F preferred stock is 8.5%.

During the year ended March 31, 2016, Company declared and made dividend payments of $1.2 billion to NGNA in relation to the series A through E preferred stock.

A summary of preferred stock is as follows:

Series	Shares Outstanding March 31, 2016	2015	Amount (par) March 31, 2016	2015	Amount (additional paid-in capital) March 31, 2016	2015
	(in millions of dollars, except per share and number of shares data)					
$0.10 par value -						
Series A	**51**	51	**$ -**	$ -	**$ 400**	$ 400
Series B	**40**	40	**-**	-	**315**	315
Series C	**96**	96	**-**	-	**750**	750
Series D	**79**	79	**-**	-	**616**	616
Series E	**1**	1	**-**	-	**10**	10
Series F	**648**	648	**-**	-	**5,368**	5,368
Total	**915**	915	**$ -**	$ -	**$ 7,459**	$ 7,459

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, 2016, the Parent had 3.9 billion of ordinary shares issued with 179,065,924 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 4.01% and 7.98%, 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, 2016 and 2015:

	Units	Weighted Average Grant Date Fair Value
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
Vested	192,265	58.41
Granted	471,613	66.05
Forfeited/Cancelled	121,787	53.41
Non-vested as of March 31, 2016	1,013,185	$ 66.48

The total expense recognized for non-vested awards was $15.7 million and $15.5 million for the years ended March 31, 2016 and 2015, respectively, and will vest over three years. The total tax benefit recorded was approximately $6.3 million and $6.2 million as of March 31, 2016 and 2015, respectively. Total expense expected to be recognized by the Parent in future periods for non-vested awards outstanding as of March 31, 2016 is $17.9 million, $11.9 million, and $2.3 million for the years ended March 31, 2017, 2018, and 2019, 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, 2016 and 2015.

The reconciliation below highlights the financial statements line items within (loss) income from discontinued operations, net of taxes for the MSA for the years ended March 31, 2016 and 2015:

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Operating revenues	**$ 51**	$ 97
Operations and maintenance	**(67)**	(69)
Other taxes	**(2)**	(8)
Other deductions, net	**(5)**	(2)
Total (loss) income before income taxes	**(23)**	18
Income tax (benefit) expense	**(10)**	8
(Loss) income from discontinued operations, net of taxes	**$ (13)**	$ 10

During the year ended March 31, 2016 bad debt expense of $20 million was recorded in order to adjust the accounts receivable to reflect the probability of collection.

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, 2016 and 2015:

	March 31,	
	2016	2015
	(in millions of dollars)	
Assets		
Accounts receivable	**$ 100**	$ 100
Allowance for doubtful accounts	**(90)**	(70)
Unbilled revenues	**11**	11
Deferred income tax assets	**37**	29
Total assets related to discontinued operations	**$ 58**	$ 70
Liabilities		
Accounts payable	**$ 22**	$ 20
Taxes accrued	**1**	1
Total liabilities related to discontinued operations	**$ 23**	$ 21

19. SUBSEQUENT EVENTS

In August 2016, KeySpan Gas East issued $700 million of unsecured long-term debt at 2.742% with a maturity date of August 1, 2026. Additionally, Massachusetts Electric issued $500 million of unsecured long-term debt at 4.004% with a maturity date of August 1, 2046.

On July 29, 2016, NEP filed a 204 application with the FERC requesting an increase in its short-term borrowing limit from $750 million to $1.5 billion. This increase will provide a source of funding for NEP while it pursues long-term financing authority in Massachusetts, New Hampshire, and Vermont.

During March 2016, Brooklyn Union issued Notice of Optional Redemption letters to the bond holders of the fixed interest rate gas facilities revenue bonds. Brooklyn Union fully repaid these bonds during April 2016.

The following table shows the bonds that have been fully paid subsequent to March 2016:

	Interest Rate	Maturity Date	March 31. 2016
			(in millions of dollars)
Gas Facilities Revenues Bonds:			
1993A and 1993B	6.37%	April 1, 2020	$ 75
1996	5.50%	January 1, 2021	154
2005A	4.70%	February 1, 2024	82
1991A and 1991B	6.95%	July 1, 2026	100
Total debts			$ 411