nationalgrid

Colonial Gas Company
d/b/a National Grid

Financial Statements

For the years ended March 31, 2013 and March 31, 2012

COLONIAL GAS COMPANY

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Independent Auditor's Report

To the Shareholder and Board of Directors of Colonial Gas Company:

We have audited the accompanying financial statements of Colonial Gas Company (the "Company"), which comprise the balance sheets as of March 31, 2013 and March 31, 2012, and the related statements of income, cash flows, capitalization and changes in shareholder's equity for the years then ended.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the 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 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 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the 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 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 financial statements referred to above present fairly, in all material respects, the financial position of Colonial Gas Company at March 31, 2013 and March 31, 2012, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

August 5, 2013

COLONIAL GAS COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31,	
	2013	2012
ASSETS		
Current assets:		
Accounts receivable	**$ 49,295**	$ 41,574
Allowance for doubtful accounts	**(4,051)**	(2,875)
Accounts receivable from affiliates	**11,940**	3,785
Unbilled revenues	**16,332**	14,509
Intercompany money pool	**12,687**	20,160
Materials, supplies and gas in storage	**11,528**	18,067
Derivative contracts	**1,336**	-
Regulatory assets	**15,209**	25,426
Current portion of deferred income tax assets	**25,129**	36,205
Prepaid and other current assets	**-**	383
Total current assets	**139,405**	157,234
Property, plant and equipment, net	**488,459**	444,637
Deferred charges and other assets:		
Regulatory assets	**252,126**	268,611
Accounts receivable from affiliates	**19,017**	18,985
Goodwill	**54,074**	54,564
Derivative contracts	**112**	-
Other deferred charges	**2,277**	2,367
Total deferred charges and other assets	**327,606**	344,527
Total assets	**$ 955,470**	$ 946,398

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

COLONIAL GAS COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31,	
	2013	2012
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 4,152**	$ 8,838
Accounts payable to affiliates	**50,905**	38,521
Tax accrued	**291**	173
Interest accrued	**2,649**	3,105
Regulatory liabilities	**72,320**	78,190
Derivative contracts	**8**	4,687
Other current liabilities	**3,400**	2,022
Total current liabilities	**133,725**	135,536
Deferred credits and other liabilities:		
Regulatory liabilities	**81,610**	75,977
Asset retirement obligations	**2,201**	2,076
Deferred income tax liabilities	**175,840**	181,714
Pension and postretirement benefits	**69,794**	74,892
Environmental remediation costs	**5,985**	6,166
Derivative contracts	**1**	610
Other deferred liabilities	**1,383**	1,403
Total deferred credits and other liabilities	**336,814**	342,838
Capitalization:		
Shareholder's equity:		
Shareholder's equity	**359,931**	343,024
Long-term debt	**125,000**	125,000
Total capitalization	**484,931**	468,024
Total liabilities and capitalization	**$ 955,470**	$ 946,398

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

COLONIAL GAS COMPANY
STATEMENTS OF INCOME
(in thousands of dollars)

	Years Ended March 31, 2013	2012
Operating revenue	**$ 255,025**	$ 270,536
Operating expenses:		
Purchased gas	**123,528**	147,037
Operations and maintenance	**59,202**	50,383
Depreciation and amortization	**22,589**	22,201
Amortization of acquisition premium	**7,888**	7,826
Other taxes	**7,262**	6,693
Total operating expenses	**220,469**	234,140
Operating income	**34,556**	36,396
Other income and (deductions):		
Interest on long-term debt	**(7,426)**	(5,863)
Other interest, including affiliate interest	**(2,039)**	(4,995)
Other income, net	**1,004**	840
Total other deductions, net	**(8,461)**	(10,018)
Income before income taxes	**26,095**	26,378
Income taxes:		
Current	**5,725**	7,616
Deferred	**4,621**	3,544
Total income tax expense	**10,346**	11,160
Net income	**$ 15,749**	$ 15,218

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

COLONIAL GAS COMPANY
STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Years Ended March 31,			
	2013		2012	
Operating activities:				
Net income	**$**	**15,749**	$	15,218
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization		**22,589**		22,201
Amortization of acquisition premium		**7,888**		7,826
Provision for deferred income taxes		**4,621**		3,544
Pension and other amortizations		**2,234**		2,218
Bad debt expense		**2,688**		1,672
Pension and other postretirement expenses		**7,226**		7,809
Pension and other postretirement contributions		**(6,752)**		(4,844)
Net environmental remediation payments		**(386)**		(526)
Changes in operating assets and liabilities:				
Accounts receivable, net and unbilled revenues		**(11,056)**		7,607
Materials, supplies and gas in storage		**6,539**		(2,608)
Accounts payable and accrued expenses		**(3,208)**		(502)
Prepaid and accrued taxes		**819**		2,368
Derivative contracts		**-**		(55)
Other liabilities		**1,358**		897
Regulatory assets and liabilities, net		**(783)**		(3,568)
Other, net		**(239)**		(350)
Net cash provided by operating activities		**49,287**		58,907
Investing activities:				
Capital expenditures		**(57,532)**		(43,947)
Cost of removal and other		**(4,615)**		(4,953)
Affiliated money pool and intercompany investing		**4,409**		(12,480)
Net cash used in investing activities		**(57,738)**		(61,380)
Financing activities:				
Affiliated money pool and intercompany borrowing		**7,293**		1,650
Parent loss tax allocation		**1,158**		-
Proceeds from long-term debt		**-**		50,000
Payments on advance from affiliates		**-**		(49,000)
Payments on debt issuance costs		-		(177)
Net cash provided by financing activities		**8,451**		2,473
Net change in cash and cash equivalents		**-**		-
Cash and cash equivalents, beginning of year		**-**		-
Cash and cash equivalents, end of year	**$**	**-**	**$**	**-**
Supplemental disclosures:				
Interest paid	**$**	**(8,620)**	$	(8,476)
Income taxes paid to Parent		**(1,984)**		(6,901)
Significant non-cash items:				
Capital-related accruals included in accounts payable		**2,064**		3,998

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

COLONIAL GAS COMPANY
STATEMENTS OF CAPITALIZATION
(in thousands of dollars)

	Interest Rate	Maturity Date	March 31, 2013	March 31, 2012
Total shareholder's equity			**$ 359,931**	$ 343,024
Long-term debt:				
Unsecured notes:				
Senior notes - Series A	3.296%	March 15, 2022	**25,000**	25,000
Senior notes - Series B	4.628%	March 15, 2042	**25,000**	25,000
Total			**50,000**	50,000
First Mortgage Bonds ("FMB"):				
FMB Series CH	8.80%	July 1, 2022	**25,000**	25,000
FMB Series A-1	7.38%	October 14, 2025	**10,000**	10,000
FMB Series A-2	6.90%	December 15, 2025	**10,000**	10,000
FMB Series A-3	6.94%	February 5, 2026	**10,000**	10,000
FMB Series B-1	7.12%	April 7, 2028	**20,000**	20,000
Total			**75,000**	75,000
Total long-term debt			**125,000**	125,000
Total capitalization			**$ 484,931**	$ 468,024

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

COLONIAL GAS COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(in thousands of dollars, except per share and number of shares data)

	Common Stock - par value $100 per share					
	Authorized Shares	**Issued and Outstanding Shares**	**Amount**	**Additional Paid-in Capital**	**Retained Earnings**	**Total**
Balance as of March 31, 2011	200	100	$ 10	$ 319,974	$ 7,822	$ 327,806
Net income	-	-	-	-	15,218	15,218
Balance as of March 31, 2012	200	100	10	319,974	23,040	343,024
Net income	-	-	-	-	15,749	15,749
Parent loss tax allocation	-	-	-	1,158	-	1,158
Balance as of March 31, 2013	200	100	$ 10	$ 321,132	$ 38,789	$ 359,931

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

COLONIAL GAS COMPANY

NOTES TO THE FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

A. Nature of Operations

Colonial Gas Company d/b/a National Grid ("the Company," "we," and "our") is a gas distribution company engaged in the transportation and sale of natural gas to approximately 192,000 residential, commercial and industrial customers in northwest Boston and Cape Cod, Massachusetts.

The Company is a wholly-owned subsidiary of KeySpan New England, LLC ("KNE LLC") and an indirectly-owned subsidiary of KeySpan Corporation ("KeySpan"). KeySpan is a wholly-owned subsidiary of National Grid USA ("NGUSA"), 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 an indirectly-owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales.

The Company has evaluated subsequent events and transactions through August 5, 2013, the date of issuance of these financial statements, and concluded that there were no events or transactions that require adjustment to or disclosure in the financial statements as of and for the year ended March 31, 2013.

B. Basis of Presentation

The financial statements for the years ended March 31, 2013 and March 31, 2012 are prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"), including the accounting principles for rate-regulated entities. The financial statements reflect the rate-making practices of the applicable regulatory authorities.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

Within the statements of cash flows, all amounts that are settled through the Regulated Money Pool (refer to Note 11, "Related Party Transactions") are treated as constructive cash receipts and payments, and therefore are recorded as such.

C. Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC") and the Massachusetts Department of Public Utilities ("DPU") provide the final determination of the rates that the Company charges its customers. In certain cases, the rate actions of the DPU can result in accounting that differs from non-regulated companies. In these cases, the Company defers costs (as regulatory assets) or recognizes obligations (as regulatory liabilities) if it is probable that such amounts will be recovered or refunded through the rate-making process, which would result in a corresponding increase or decrease in future rates.

D. Revenue Recognition

Customers are generally billed on a monthly basis. Revenues include unbilled amounts related to the estimated gas usage that occurred from the most recent meter reading to the end of each month.

The cost of gas adjustment factor ("CGAF") requires the Company to adjust rates semi-annually or, based on certain criteria, adjust rates monthly for firm gas sales in order to track changes in the cost of gas. The CGAF includes a prior period reconciliation for the over- or under- recovery of actual costs and collections incurred during the prior season. The Company recovers the gas cost portion of bad debt write-offs through the CGAF. In addition, through a local distribution adjustment factor, the Company is allowed to recover the amortization of environmental response costs associated with former manufactured gas plant ("MGP") sites, costs related to the Company's various energy efficiency programs, costs related to the Company's pension and postretirement benefits other than pensions ("PBOP"), targeted infrastructure, replacement costs and other specified costs from the Company's firm sales and transportation customers.

As approved by the DPU, the Company is allowed to pass through commodity-related costs to customers, and does so through an adjustment mechanism that results in recovery of those costs from or refunds to customers over a six month period.

With respect to base distribution rates, the DPU has also approved a Revenue Decoupling Adjustment Factor ("RDAF"), which requires the Company to adjust its base rates semi-annually to reflect the over- or under- recovery of the Company's targeted base distribution revenues from the prior season. Revenue decoupling is a rate-making mechanism that breaks the link between the Company's base revenue requirement and sales. This mechanism allows the Company to offer various energy efficiency measures to its customers without financial detriment to the Company resulting from reductions in gas usage.

The relative proportions of the Company's revenues from the sale and delivery of gas to residential and non-residential customers for the years ended March 31, 2013 and March 31, 2012 are as follows:

	March 31,	
	2013	2012
Residential	**73%**	73%
Commercial and Industrial	**27%**	27%

E. Property, Plant and Equipment

Property, plant and equipment is stated at original cost. The cost of additions to property, plant and equipment and replacements of retired units of property are capitalized. Costs include direct material, labor, overhead, and allowance for funds used during construction ("AFUDC"). The cost of renewals and betterments that extend the useful life of property, plant and equipment are also capitalized. The cost of repairs, replacements, and major maintenance projects, which do not extend the useful life or increase the expected output of the asset, are expensed as incurred. Depreciation is generally computed over the estimated useful life of the assets using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the DPU. Whenever 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 average composite rates and average service lives for the years ended March 31, 2013 and March 31, 2012 are as follows:

	March 31,	
	2013	2012
Composite rates - depreciation	**2.2%**	2.3%
Composite rates - cost of removal	**1.2%**	1.2%
Total composite rates	**3.4%**	3.5%
Average service life	**43 years**	43 years

The Company's depreciation expense includes estimated costs to remove property, plant and equipment, which is recovered through the rates charged to customers. At March 31, 2013 and March 31, 2012, the Company had cumulative costs recovered in excess of costs incurred totaling $81.5 million and $75.6 million, respectively. These amounts are reflected as regulatory liabilities in the accompanying balance sheets.

In accordance with applicable regulatory accounting guidance, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated facilities. The equity component of AFUDC is a non-cash amount within the statements of income. AFUDC is capitalized as a component of the cost of property, plant and equipment, with an offsetting credit to other income, net for the equity component and other interest expense for the debt component in the accompanying statements of income. After construction is completed, the Company is permitted to recover these costs through inclusion in its rate base and corresponding depreciation expense.

The components of AFUDC capitalized and composite AFUDC rates for the years ended March 31, 2013 and March 31, 2012 are as follows:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Debt	**$ 297**	$ 209
Equity	**822**	480
	$ 1,119	$ 689
Composite AFUDC	**6.5%**	8.6%

F. Goodwill

Goodwill represents the excess of the purchase price of a business over the fair value of the tangible and intangible assets acquired, net of the fair value of liabilities assumed and the fair value of any non-controlling interest in the acquisition. The Company tests goodwill for impairment annually on January 31, and whenever events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount.

The goodwill impairment analysis is comprised of two steps. In the first step, the estimated fair value of the reporting unit is compared with its carrying value. If the fair value exceeds the carrying value, goodwill is not impaired and no further analysis is required. If the carrying value exceeds the 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 Company calculated the fair value of the reporting unit in the performance of its annual goodwill impairment test for the fiscal year ended March 31, 2013 utilizing both income and market approaches.

- To estimate fair value utilizing the income approach, the Company used a discounted cash flow methodology incorporating its most recent business plan forecasts together with a projected terminal year calculation. Key assumptions used in the income approach were: (a) expected cash flows for the period from April 1, 2013 to March 31, 2018; (b) a discount rate of 5.5%, which was based on the Company's best estimate of its after-tax weighted-average cost of capital; and (c) a terminal growth rate of 2.25%, based on the Company's expected long term average growth rate in line with estimated long term US economic inflation.

- To estimate fair value utilizing the market approach, the Company followed a market comparable methodology. Specifically, the Company applied a valuation multiple of earnings before interest, taxes, depreciation and amortization ("EBITDA"), derived from data of publicly-traded benchmark companies, to business operating data. Benchmark companies were selected based on comparability of the underlying business and economics. Key assumptions used in the market approach included the selection of appropriate benchmark companies and the selection of an EBITDA multiple of 10.0, which the Company believes is appropriate based on comparison of its business with the benchmark companies.

The Company ultimately determined the fair value of the business using 50% weighting for each valuation methodology, as it believes that each methodology provides equally valuable information. Based on the resulting fair value from the annual analyses, the Company determined that no adjustment of the goodwill carrying value was required at March 31, 2013 or March 31, 2012.

G. Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is calculated by applying a reserve factor to outstanding receivables. The reserve factor is based upon historical write-off experience and assessment of customer collectability.

H. Materials, Supplies and Gas in Storage

Materials and supplies are stated at the lower of weighted average cost or market and are expensed or capitalized into specific capital additions as used. At March 31, 2013 and March 31, 2012, the balance of materials and supplies was $0.1 million. 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, 2013 and March 31, 2012.

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 through the cost of gas purchased directly to customers along with any applicable authorized delivery surcharge adjustments. Accordingly, the value of gas in storage does not fall below the cost to the Company. Gas costs passed through to customers are subject to periodic regulatory approvals and are reported periodically to the DPU. At March 31, 2013 and March 31, 2012, gas in storage was $11.4 million and $18.0 million, respectively.

I. Income and Other Taxes

Federal 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 financial statement carrying amounts and the tax basis of existing assets and liabilities. National Grid North America Inc. ("NGNA," formerly National Grid Holdings Inc.), an indirectly-owned subsidiary of National Grid plc and the intermediate holding company of NGUSA, files consolidated federal tax returns including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return method. As a member, the Company settles its current tax liability or benefit each year with NGNA pursuant to a tax sharing arrangement between NGNA and its members. Benefits allocated by NGNA are treated as capital contributions.

Deferred income taxes reflect the tax effect of net operating losses, capital losses and general business credit carryforwards and the net tax effects of temporary differences between the carrying amount of assets and liabilities for financial statement and income tax purposes, as determined under enacted tax laws and rates. 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. Additionally, the Company follows the current accounting guidance relating to uncertainty in income taxes which applies to all income tax positions reflected in the accompanying balance sheets that have been included in previous tax returns or are expected to be included in future tax returns. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not, based on the technical merits, that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

The Company collects certain taxes from customers such as sales taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas. The Company accounts for taxes that are imposed on customers (such as sales taxes) on a net basis (excluded from revenues).

J. Employee Benefits

The Company follows the accounting guidance for defined benefit PBOP plans for recording pension expenses and resulting plan asset and liability balances. The guidance requires employers to fully recognize all pension and postretirement plans' funded status on the balance sheets as a net liability or asset. In the case of regulated entities, the offset to such net liability or asset is recorded as a regulatory asset or liability when the balance will be recovered from or refunded to customers in future rates. The Company has determined that such amounts will be included in future rates and follows the regulatory format for recording the balances. The Company measures and records its

PBOP obligations at the year-end date. PBOP assets are measured at fair value, using the year-end market value of those assets.

K. Derivatives

Derivatives are financial instruments that derive their value from the price of an underlying item such as interest rates, foreign exchange, credit spreads, commodities, equity or other indices. Derivatives enable their users to manage their exposure to these market or credit risks. The Company uses derivative instruments to manage its operational market risks from commodities and economically hedge a portion of the Company's exposure to commodity price risk. When economic hedge positions are in effect, the Company is exposed to credit risks in the event of non-performance by counterparties to derivative contracts (hedging transactions), as well as non-performance by the counterparties of the underlying transactions.

Commodity Derivative Instruments – Regulated Accounting

The Company utilizes derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases. The Company's strategy is to minimize fluctuations in firm gas sales costs to the Company's customers. The accounting for these derivative financial instruments is subject to the current accounting guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or deferred assets or liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the accompanying balance sheets. Gains or losses on the settlement of these contracts are initially deferred and then refunded to or collected from the Company's customers consistent with regulatory requirements.

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

Balance Sheet Offsetting

Accounting guidance related to derivatives permits the offsetting of fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) arising from derivative instrument(s) recognized at fair value executed with the same counterparty under a master netting arrangement. The Company's accounting policy is to not offset such amounts, and to record and present the fair value of derivative instrument(s) on a gross basis in the accompanying balance sheets.

L. Fair Value Measurements

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

Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date;

Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data; and

Level 3 — unobservable inputs, such as internally-developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs.

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

M. New and Recent Accounting Guidance

Accounting Guidance Adopted in Fiscal Year 2013

Fair Value Measurements

In May 2011, the Financial Accounting Standards Board ("FASB") issued accounting guidance that amended existing fair value measurement guidance. The amendment was issued with a goal of achieving common fair value measurement and disclosure requirements in GAAP and International Financial Reporting Standards. Consequently, the guidance changes the wording used to describe many of the requirements in GAAP for measuring fair value, requires new disclosures about fair value measurements, and changes specific applications of the fair value measurement guidance. Some of the amendments clarify the FASB's intent about the application of existing fair value measurement requirements. Other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements including, but not limited to: fair value measurement of a portfolio of financial instruments; fair value measurement of premiums and discounts; and additional disclosures about fair value measurements. This guidance became effective for financial statements issued for annual periods (for non-public entities such as the Company) beginning after December 15, 2011. The Company adopted this guidance for the fiscal year ended March 31, 2013, which only impacted its fair value disclosures. There were no changes to the Company's approach to measuring fair value as a result of adopting this new guidance.

Goodwill Impairment

In September 2011, the FASB issued accounting guidance related to goodwill impairment testing, whereby an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is not required. Otherwise, the entity is required to perform the two-step impairment test. This guidance became effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The Company adopted this guidance in its fiscal year ended March 31, 2013 and did not elect the option to perform a qualitative analysis.

Accounting Guidance Not Yet Adopted

Offsetting Assets and Liabilities

In December 2011, the FASB issued accounting guidance requiring enhanced disclosure related to offsetting assets and liabilities. Under the new guidance, reporting entities will be required to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting agreement, such as for derivatives. In January 2013, the FASB issued additional guidance to clarify that the specific instruments and activities that should be considered in these disclosures will be limited to recognized derivatives, repurchase and reverse repurchase agreements, and securities lending transactions. This guidance is effective for fiscal years, and interim periods within those years, beginning after January 1, 2013, and is to be applied retrospectively. The Company will begin including the new required disclosures in its fiscal year 2014 interim financial statements as applicable and does not expect any impact on its financial position, results of operations, or cash flows.

N. Reclassifications

Certain reclassifications have been made to the financial statements to conform prior year's data to the current year's presentation. These reclassifications had no effect on the Company's results of operations and cash flows.

Note 2. Rates and Regulation

The following table presents the Company's regulatory assets and regulatory liabilities at March 31, 2013 and March 31, 2012:

	March 31, 2013	March 31, 2012
	(in thousands of dollars)	
Regulatory assets		
Current:		
Recovery of acquisition premium	**$ 8,200**	$ 7,826
Revenue decoupling	**2,873**	8,286
Postretirement benefits	**2,078**	2,078
Environmental costs	**482**	394
Derivative contracts	**8**	4,687
Other	**1,568**	2,155
Total	**15,209**	25,426
Non-current:		
Recovery of acquisition premium	**208,417**	215,873
Postretirement benefits	**33,394**	41,076
Regulatory deferred tax asset	**4,290**	4,027
Environmental costs	**3,450**	3,754
Derivative contracts	**1**	610
Other	**2,574**	3,271
Total	**252,126**	268,611
Regulatory liabilities		
Current:		
Gas costs	**64,536**	73,875
Alliance profit	**5,982**	4,315
Derivative contracts	**1,336**	-
Other	**466**	-
Total	**72,320**	78,190
Non-current:		
Cost of removal	**81,451**	75,551
Derivative contracts	**112**	-
Other	**47**	426
Total	**81,610**	75,977
Net regulatory assets	**$ 113,405**	$ 139,870

Recovery of acquisition premium: This represents the unrecovered amount (plus related taxes) by which the purchase price paid exceeded the net book value of the Company's assets in the 1998 acquisition of the Company by Eastern Enterprises, Inc. ("Eastern"). In exchange for certain rate concessions and the achievement of certain merger savings targets, the DPU has allowed the Company to recover the acquisition premium through rates for the next 26 years (through August 2039). Refer to Note 9, "Goodwill," for additional information.

Postretirement benefits: This amount primarily represents the excess costs of the Company's pension and postretirement benefit 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. Also included within this amount are certain pension deferral amounts from prior to the 2007 acquisition of KeySpan by NGUSA, which are being recovered in rates over a 10-year period ending August 2017.

Environmental costs: This regulatory asset represents deferred costs associated with the estimated costs to investigate and perform certain remediation activities at former MGP sites and related facilities. The Company's rate plans provide for the recovery of previously-incurred costs over a 7-year recovery period. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates.

Gas costs: 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 the DPU. These amounts will be refunded to customers over the next year.

Alliance profit: This regulatory liability represents a portion of deferred margins from off-system sale transactions. Under current rate orders, the Company is required to return 90% of margins earned from such optimization transactions to firm customers. The amounts deferred at the balance sheet date will be refunded to customers over the next year.

Cost of removal: The Company's depreciation expense includes estimated costs to remove property, plant and equipment, which is recovered through the rates charged to customers. This regulatory liability represents cumulative costs recovered in excess of costs incurred. For a vast majority of its gas distribution assets, the Company uses these funds to remove the asset so a new one can be installed in its place.

Carrying Charges

The regulatory items above are not included in the utility rate base at the time the expenses are incurred or the revenue is billed. The Company records carrying charges on the regulatory balances related to gas costs, postretirement benefits, environmental costs and revenue decoupling 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. The Company anticipates recovering these costs in rates concurrently with future cash expenditures. If recovery is not concurrent with the cash expenditures, the Company will record the appropriate level of carrying charges.

During the years ended March 31, 2013 and March 31, 2012, the Company recognized net carrying charges of $1.0 million and $2.1 million, respectively, which is included in other interest, including affiliate interest and other income, net in the accompanying statements of income.

Rate Matters

In November 2010, the DPU issued an order in the Company's 2010 rate case approving a revenue increase of $16.5 million based upon a 9.75% rate of return on equity and a 50% equity ratio. In November 2010, the Company filed two motions in response to the DPU's November 2010 rate case order, whereby in its motion for recalculation, the Company had requested that the DPU recalculate certain adjustments that it made in determining the $16.5 million increase approved in its order, which would result in an additional $5.5 million. On October 26, 2011, the DPU ruled on the Company's Motion for recalculation awarding the Company an increase of $0.2 million of the $5.5 million request, effective November 1, 2011. On January 31, 2013, the DPU ruled on the Company's motion for reconsideration and upheld its decision on all of the financial matters raised by the Company with the exception of the issue of merger related costs. The Company was able to demonstrate in its motions that it had achieved savings related to its 1998 acquisition by the former Eastern in excess of $12.3 million per year, which is the full pre-tax annual level of merger costs amortized over the 30 year period ended August 31, 2039, thereby increasing by $4.5 million to the full amount of annualized merger related costs from $7.8 million to $12.3 million. The combined effect of the DPU's orders is a total revenue increase of $21.2 million in this proceeding, with the $4.5 million reflected in rates effective February 1, 2013.

In May 2011, May 2012, and May 2013, the Company made filings with the DPU for recovery of cumulative capital costs related to infrastructure replacement for approximately $0.4 million, $2.4 million and $3.8 million, respectively (the incremental investments were $1.9 million and $1.5 million for the May 2012 and May 2013 filings, respectively). The May 2011 and May 2012 requests have been reflected in rates effective on the following November 1, with a final resolution pending before the DPU. The May 2013 request is currently being reviewed by the DPU and, if approved, will be reflected in rates effective November 1, 2013.

On August 3, 2012, the Company submitted its peak revenue decoupling mechanism ("RDM") filing with the DPU proposing to surcharge customers $5.3 million and deferring $5.9 million which exceeded the allowable cap under the Company's RDM. The Company expects to recover the remaining $5.9 million in the future. On October 12, 2012, the DPU approved the Company's RDAF effective November 1, 2012 subject to further investigation and reconciliation. On January 31, 2013, the Company submitted its off peak RDM filing with the DPU proposing a surcharge to customers of $1.1 million, which is below the allowable cap. The DPU approved the off peak RDAF effective May 1, 2013.

Other Regulatory Matters

In August 2011, the Company and its affiliate, Boston Gas Company ("Boston Gas") sought approval for six natural gas asset management services agreements between the Company and one of five counterparties. On October 17, 2011, the DPU approved the agreements, which commenced on November 1, 2011 and expired on March 31, 2012. Under these agreements, the Company was eligible to share in 25% of the asset management fees that are clearly attributable to capacity release activities above the prior year's margin threshold as directed in the DPU's Order, and pursuant to the incentive sharing mechanism set forth in DPU 91-141-A. In conjunction with Boston Gas, the Company earned $1 million from May 2011 to April 2012 per the mechanism. Effective February 20, 2013, by order of the DPU, the mechanism for the sharing of margins under such optimization transactions has been revised whereby the Company retains 10% of all margins earned from contracts entered into after the effective date, without regard to a threshold. There were no such agreements in effect as of March 31, 2013.

Associated with its general rate case, the DPU opened an investigation to address the allocation and assignment of costs to the Company by the National Grid service companies. In June 2011, the Attorney General's Office requested that the DPU expand the scope of the audit to address the allocation and assignment of costs to the Company's electric distribution affiliates by the National Grid service companies and to review National Grid's cost allocation practices. The Company has agreed to expand the scope of the audit to its Massachusetts electric distribution affiliates. On March 12, 2012, the DPU issued an order confirming that the scope of the audit would include the Massachusetts electric distribution companies and directing the Company to revise its draft request for proposal consistent with the DPU's order and re-file it within seven days. The Company cannot predict the outcome of this proceeding.

Energy Efficiency

The Company and Boston Gas operate a single combined Three-Year Energy Efficiency Plan. The most recent Plan covering the period 2013 through 2015 was approved by the DPU on January 31, 2013 with a three-year budget of $290.8 million ($94.2 million for 2013, $97.0 million for 2014, and $99.6 million for 2015). In addition, the Company and Boston Gas have the opportunity to recover a total performance incentive over the three-year Plan of approximately $8.3 million with a fixed amount to be collected in the budget for each year of the Plan. After the conclusion of the Plan, the Company will reconcile the energy efficiency surcharge amounts as well as amount collected for the performance incentives.

Note 3. Employee Benefits

Pension Benefits

The Company participates with certain other NGUSA subsidiaries in non-contributory defined benefit plans (the "Pension Plans"), covering substantially all employees - The KeySpan Retirement Plans, National Grid USA Companies' Executive SERP, Excess Benefit Plan of KeySpan Corp., Supplemental Retirement of KeySpan Corp. and KeySpan Benefit Plan for Retired Colonial Gas Management and Union Employees. The Pension Plans provide union employees with a retirement benefit and non-union employees hired before January 1, 2011 with a retirement benefit. The Company contributed $5.9 million and $4.4 million for the years ended March 31, 2013 and March 31, 2012, respectively, to the trusts of its qualified Pension Plans. Supplemental nonqualified, non-contributory executive programs provide additional defined pension benefits for certain executives. The Pension Plans' costs are allocated to the Company based on plan participant data as determined by the Company's actuaries.

The Pension Plans' assets are commingled and cannot be allocated to an individual company. The Pension Plans' costs and liabilities are first directly charged to the Company based on the Company's employees that participate in the Pension Plans. Costs and liabilities associated with affiliated service companies' employees are then allocated as part of the labor burden for work performed on the Company's behalf. The Company is subject to certain deferral accounting requirements mandated by the DPU for pension costs. Any variation between actual costs and amounts used to establish rates is deferred as a regulatory asset or a regulatory liability and collected from or refunded to customers in subsequent periods. The Company's net pension expense directly charged and allocated from affiliated service companies, net of capital, for the years ended March 31, 2013 and March 31, 2012 was $5.9 million and $5.8 million, respectively. These liabilities are included in postretirement benefits in the accompanying balance sheets.

KeySpan's unfunded pension obligations at March 31, 2013 and March 31, 2012 were $892.7 million and $929.8 million at March 31, 2013 and March 31, 2012, respectively. The Company's portion of the unfunded pension obligation in the accompanying balance sheets at March 31, 2013 and March 31, 2012 was $38.6 million and $43.6 million, respectively.

Postretirement Benefits Other than Pension

The PBOP Plans have not been merged with other NGUSA plans and therefore, continue to remain separate plans of the Company. The PBOPs 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 PBOP assets are commingled and the Company's portion of the KeySpan Master Union Trust Plan is approximately 0.2%. PBOP expenses are included in operations and maintenance expenses in the accompanying statements of income. The Company is subject to certain deferral accounting requirements mandated by the DPU for PBOP costs. Any variation between actual costs and amounts used to establish rates is deferred as a regulatory asset or a regulatory liability and collected from or refunded to customers in subsequent periods.

The Company's unfunded PBOP obligations at March 31, 2013 and March 31, 2012 were $31.2 million and $31.3 million, respectively.

Net Periodic Costs

The following table summarizes the Company's PBOP cost during the years ended March 31, 2013 and March 31, 2012:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Service cost, benefits earned during the year	**$ 359**	$ 408
Interest cost	**1,483**	1,565
Expected return on plan assets	**(79)**	(72)
Net amortization of prior service costs	**404**	438
Net amortization of unrecognized loss	**334**	359
Settlement/curtailment charge	**112**	362
Total	**$ 2,613**	$ 3,060

The following table summarizes the Company's other pre-tax changes in PBOP plan assets and benefit obligations recognized in the Company's regulatory assets and accounts receivable from affiliates for the years ended March 31, 2013 and March 31, 2012:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Net actuarial loss	**$ (1,093)**	$ 3,293
Amortization of loss	**(334)**	(359)
Amortization of prior service costs	**(516)**	(800)
Total	**$ (1,943)**	$ 2,134

The estimated PBOP net actuarial loss and prior service cost of $0.4 million and $0.4 million, respectively, will be amortized from regulatory assets during the year ended March 31, 2014.

The following table summarizes the Company's amounts in regulatory assets and accounts receivable from affiliates on the accompanying balance sheets that have not yet been recognized as components of net actuarial loss at March 31, 2013 and March 31, 2012:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Net actuarial loss	**$ 7,580**	$ 9,003
Prior service cost	**1,354**	1,874
Total	**$ 8,934**	$ 10,877

Changes in Benefit Obligations and Assets

The following table summarizes the change in PBOB Plans' benefit obligation and funded status:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ (32,533)**	$ (27,664)
Service cost	**(359)**	(408)
Interest cost on projected benefit obligation	**(1,483)**	(1,565)
Net actuarial gain (loss)	**277**	(4,133)
Benefits paid	**780**	386
Curtailments/settlements	**802**	851
Benefit obligation at end of year	**(32,516)**	(32,533)
Change in plan assets:		
Fair value of plan assets at beginning of year	**1,229**	1,142
Actual return on plan assets	**93**	61
Employer contributions	**766**	412
Benefits paid	**(780)**	(386)
Fair value of plan assets at end of year	**1,308**	1,229
Funded status	**$ (31,208)**	$ (31,304)

The Company's portion of PBOP liability is recognized as postretirement benefits in the accompanying balance sheets.

The Company is the sponsor of the PBOP Plans. A portion of the participants of these plans work for certain other affiliates. As such, a portion of the PBOP expenses and the unfunded obligation has been allocated to these affiliates. The Company has recorded an intercompany receivable of $19.0 million as of March 31, 2013 and March 31, 2012 for the amount of the unfunded obligation due from these affiliates.

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following PBOP benefit payments subsequent to March 31, 2013:

		Postretirement Benefits (in thousands of dollars)
For the Years Ended March 31,		
2014	$	1,265
2015		1,380
2016		1,454
2017		1,530
2018		1,598
Thereafter		8,813
Total	$	16,040

Assumptions

The weighted average assumptions used to determine the benefit obligations and net periodic cost for the PBOPs for the years ended March 31, 2013 and March 31, 2012 are as follows:

	PBOPs			
	Benefit Obligation		Net Periodic Benefit Cost	
	2013	2012	**2013**	2012
Discount rate	**4.70%**	5.10%	**5.10%**	5.90%
Expected long-term rate of return on asset	**7.50%**	7.50%	**7.50%**	7.75%

The Company selects its discount rate assumption based upon rates of return on high quality corporate bond yields in the marketplace as of each measurement date. Specifically, the Company uses the Aon Hewitt AA Only 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 assumption. 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.

A one-percentage-point change in the assumed health care trend rate would have the following effects on the financial statements as of and for the year ended March 31, 2013:

One-Percentage-Point	**Increase**	/	**(Decrease)**
	(in thousands of dollars)		
Total of service cost plus interest cost	$ 290		$ (231)
Postretirement benefit obligation	4,660		(3,771)

The Company expects to make $1.3 million in future contributions to the PBOP plans during the year ended March 31, 2014.

Plan Assets

KeySpan 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 plan's liabilities and funded status and results in the determination of the allocation of assets across equity and fixed income. 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. Investment risk and return is reviewed by NGUSA's investment committee on a quarterly basis.

The target asset allocations for the benefit plans as of March 31, 2013 and March 31, 2012 are as follows:

	Pension Plans		PBOPs	
	2013	2012	**2013**	2012
U.S. equities	**20%**	20%	**40%**	40%
Global equities	**7%**	7%	**6%**	6%
Global tactical asset allocation	**10%**	10%	**9%**	9%
Non-U.S. equities	**10%**	10%	**21%**	21%
Fixed income	**40%**	40%	**24%**	24%
Private equity	**5%**	5%	-	-
Real estate	**5%**	5%	-	-
Infrastructure	**3%**	3%	-	-
	100%	100%	**100%**	100%

Fair Value Measurements

KeySpan determines the fair value of plan assets using unadjusted quoted prices in active markets (Level 1) or pricing inputs that are observable (Level 2) whenever that information is available. KeySpan uses unobservable inputs (Level 3) to estimate fair value only when relevant observable inputs are not available. Assets are classified within this fair value hierarchy based on the lowest level of inputs which significantly affect the fair value measurement.

The table depicted below sets forth by level, within the fair value hierarchy, the Company's 0.2% portion of the KeySpan Master Union Trust Plan assets for the PBOPs, as of March 31, 2013 and March 31, 2012:

	March 31, 2013			
	Level 1	Level 2	Level 3	Total
	(in thousands of dollars)			
Asset types:				
Cash and cash equivalents	$ 23	$ 69	$ -	$ 92
Accounts receivable	4	-	-	4
Accounts payable	(3)	-	-	(3)
Equity	206	476	25	707
Fixed income securities	18	363	2	383
Private Equity	-	-	20	20
Global tactical asset allocation	37	52	11	100
Alternative investments	-	-	5	5
Total	$ 285	$ 960	$ 63	$ 1,308

	March 31, 2012			
	Level 1	Level 2	Level 3	Total
	(in thousands of dollars)			
Asset types:				
Cash and cash equivalents	$ 9	$ 15	$ -	$ 24
Accounts receivable	5	1	-	6
Accounts payable	(4)	-	-	(4)
Equity	277	385	18	680
Fixed income securities	162	230	-	392
Private Equity	-	-	32	32
Global tactical asset allocation	34	52	13	99
Total	$ 483	$ 683	$ 63	$ 1,229

Cash and Cash Equivalents

Cash and cash equivalents are classified as Level 1 as they can be priced daily. Active reserve funds, reserve deposits, commercial paper, repurchase agreements and commingled cash equivalents are classified as Level 2 as they can be valued using other significant observable inputs.

Accounts Receivable and Accounts Payable

Accounts receivable and accounts payable are classified in the same level as the investments to which they relate.

Equity

Common stocks are valued using the official close of the primary market on which the individual securities are traded.

Equity securities are 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, therefore they would be 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 would be classified as Level 2 investments. Investments that are not publicly traded and valued using unobservable inputs would be classified as Level 3 investments. Commingled funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the net asset value ("NAV") per fund share, derived from the underlying securities' quoted prices in active markets, and is classified as Level 2 investments. Investments in commingled funds with redemption restrictions and that use NAV are classified as Level 3 investments.

Fixed Income Securities

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

Private Equity

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 net asset value.

Investment in private equity is primarily invested in 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 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. The funds utilize valuation techniques consistent with the market, income, and cost approaches to measure the fair value of certain real estate investments. As a result, the Company classifies these investments as Level 3 investments.

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

Global Tactical Asset Allocation

Assets held in global tactical asset allocation fund 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. These assets are invested through commingled funds, which are generally classified as Level 2. However, assets are classified as Level 3 when fund prices are based on uncorroborated and unobservable inputs.

The following is a summary of changes in the fair value of the PBOP's Level 3 investments:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Balance at beginning of year	**$ 63**	$ 96
Transfers out of Level 3	**(8)**	(40)
Transfers into Level 3	**2**	-
Actual gain or loss on plan assets - included in regulatory assets and liabilities		
Realized gains	**7**	1
Unrealized (losses) gains	**(4)**	2
Purchases	**33**	18
Sales	**(30)**	(14)
Balance at end of year	**$ 63**	$ 63

Note 4. Property, Plant and Equipment

At March 31, 2013 and March 31, 2012, property, plant and equipment at cost along with accumulated depreciation and amortization are as follows:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Plant and machinery	**$ 630,830**	$ 600,814
Land and buildings	**28,393**	27,894
Assets in construction	**35,419**	15,324
Software and other intangibles	**13,560**	13,558
Total	**708,202**	657,590
Accumulated depreciation and amortization	**(219,743)**	(212,953)
Property, plant and equipment, net	**$ 488,459**	$ 444,637

Note 5. Derivatives

In the normal course of business, the Company enters into commodity derivative instruments, such as swaps and physical contracts that are principally used to manage commodity prices associated with natural gas distribution operations. These financial exposures are monitored and managed as an integral part of the Company's overall financial risk management policy. The Company generally engages in activities at risk only to the extent that those activities fall within commodities and financial markets to which it has a physical market exposure in terms and volumes consistent with its core business.

The Company utilizes derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases. The Company's strategy is to minimize fluctuations in firm gas sales prices to the Company's customers.

The following are commodity volumes in dekatherms ("dths") associated with derivative contracts as of March 31, 2013 and March 31, 2012:

		March 31,	
		2013	2012
		(in thousands)	
Physical Contracts:	Gas purchase (dths)	**105**	21
Financial Contracts:	Gas swap (dths)	**4,650**	4,330
		4,755	4,351

The following table presents the Company's derivative assets and liabilities that are included in the accompanying balance sheets for the above contracts at March 31, 2013 and March 31, 2012:

	Asset Derivatives March 31,			Liability Derivatives March 31,	
	2013	2012		**2013**	2012
	(in thousands of dollars)			*(in thousands of dollars)*	
Current assets:			Current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas purchase contracts	**$ 4**	$ -	Gas purchase contracts	**$ -**	$ -
Gas swap contracts	**1,332**	-	Gas swap contracts	**8**	4,687
	1,336	-		**8**	4,687
Deferred charges and other assets:			Deferred credits and other liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas swap contracts	**112**	-	Gas swap contracts	**1**	610
	112	-		**1**	610
Total	**$ 1,448**	$ -	Total	**$ 9**	$ 5,297

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 on the accompanying statements of income.

The following table presents the impact of the change in the fair value of the Company's derivative contracts had on the accompanying balance sheets and statements of income for the years ended March 31, 2013 and March 31, 2012:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Regulatory assets:		
Gas purchase contracts	**$ -**	$ (1)
Gas swap contracts	**(5,288)**	3,965
	(5,288)	3,964
Regulatory liabilities:		
Gas purchase contracts	**4**	-
Gas swap contracts	**1,444**	(257)
	1,448	(257)
Total (decrease) increase in net regulatory assets	**$ (6,736)**	$ 4,221
Other income (deduction):		
Gas swap contracts	**$ -**	$ 55

The change in the fair value of the derivative contracts not subject to rate recovery is included in other income in the accompanying statements of income during the year ended March 31, 2012. During the year ended March 31, 2013, the Company did not hold any such contracts.

Credit and Collateral

Derivative contracts are primarily used to manage exposure to market risk arising from changes in commodity prices. In the event of non-performance by a counterparty to a derivative contract, the desired impact may not be achieved. The risk of counterparty non-performance is generally considered a credit risk and is actively minimized by assessing each counterparty credit profile and negotiating appropriate levels of collateral and credit support.

The credit policy for commodity transactions is owned and monitored by the NGUSA Energy Procurement Risk Management Committee, and establishes controls and procedures to determine, monitor and minimize the credit risk of counterparties. Counterparty credit exposure is monitored, 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 reduces its exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. The Company's credit exposure for all 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 $1.4 million and $5.3 million as of March 31, 2013 and March 31, 2012, respectively.

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. At March 31, 2012, the aggregate fair value of the Company's derivative instruments with credit-risk-related contingent features that were in a liability position was $5.3 million; the Company had no collateral posted for these instruments at March 31, 2013 and March 31, 2012, respectively. At March 31, 2013, the Company did not have any derivative instruments with credit-risk-related contingent features.

Note 6. Fair Value Measurements

The Company measures commodity derivatives at fair value. The following table presents assets and liabilities measured and recorded at fair value in the accompanying balance sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2013 and March 31, 2012:

	March 31, 2013			
	Level 1	Level 2	Level 3	Total
	(in thousands of dollars)			
Assets:				
Financial derivative contracts	$ -	$ 1,444	$ -	$ 1,444
Physical derivative contracts	-	4	-	4
Liabilities:				
Financial derivative contracts	-	9	-	9
Net assets	$ -	$ 1,439	$ -	$ 1,439

	March 31, 2012			
	Level 1	Level 2	Level 3	Total
	(in thousands of dollars)			
Liabilities:				
Financial derivative contracts	$ -	$ 5,297	$ -	$ 5,297

The following is a description of the inputs to and valuation techniques used to measure the fair values above:

Derivative contracts

The Company's Level 2 fair value derivative instruments consist of over-the-counter ("OTC") gas swaps and forward physical gas deals valued based on pricing inputs obtained from the New York Mercantile Exchange ("NYMEX") and Intercontinental Exchange ("ICE"), except in cases in which ICE publishes seasonal averages or there were no transactions within the last seven days. We may utilize discounting based on quoted interest rate curves that may include a liquidity reserve calculated based on the bid/ask spread for our 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.

Level 3 fair value derivative instruments consist of the Company's complex and structured OTC physical gas transactions valued based on internally-developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulations, and Financial Engineering Associates libraries are used for valuing such instruments. A derivative instrument is designated as Level 3 when it is valued based on a forward curve that is internally developed, extrapolated or derived from a market observable curve with correlation coefficients less than 95%, optionality is present, or if non-economic assumptions are made.

Year to Date Level 3 Movement Table

The following table presents the fair value reconciliation of Level 3 derivative assets and liabilities measured at fair value on a recurring basis during the years ended March 31, 2013 and March 31, 2012:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Balance, at beginning of year	**$ -**	$ (1)
Total gains and losses included in regulatory assets and liabilities	**6**	(40)
Purchases	**(473)**	(1,719)
Settlements	**467**	1,760
Balance, at end of year	**$ -**	$ -
The amount of total gains or losses for the period included in net income attributed to the change in unrealized gains or losses related to non-regulatory assets and liabilities	**$ -**	$ -

A transfer into Level 3 represents existing assets or liabilities that were previously categorized at a higher level for which the inputs became unobservable. 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 or out of Level 3 during the years ended March 31, 2013 and March 31, 2012.

Other Fair Value Measurements

The fair market value of the Company's long-term debt was estimated based on the quoted market prices for similar issues or on the current rates offered to the Company for debt of the same remaining maturity. The fair value of long-term debt at March 31, 2013 and March 31, 2012 was $154.4 million and $145.7 million, respectively.

All other financial instruments on the balance sheets such as money pool and intercompany balances, accounts receivable and accounts payable are stated at cost, which approximates fair value.

Note 7. Income Taxes

The components of federal and state income tax expense are as follows:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Current tax expense:		
Federal	**$ 3,964**	$ 5,503
State	**1,761**	2,113
Total	**5,725**	7,616
Deferred tax expense (benefit):		
Federal	**4,864**	4,363
State	**(40)**	(616)
Total	**4,824**	3,747
Amortized investment tax credits, net (1)	**(203)**	(203)
Total deferred tax expense	**4,621**	3,544
Total income tax expense	**$ 10,346**	$ 11,160

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

A reconciliation between the expected federal income tax expense, using the federal statutory rate of 35%, to the Company's actual income tax expense for the years ended March 31, 2013 and March 31, 2012 is as follows:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Computed tax	**$ 9,134**	$ 9,232
Change in computed taxes resulting from:		
State income tax, net of federal benefit	**1,118**	973
Investment tax credit	**(203)**	(203)
Other items, net	**297**	1,158
Total	**1,212**	1,928
Federal and state income taxes	**$ 10,346**	$ 11,160

Significant components of the Company's net deferred tax assets and liabilities at March 31, 2013 and March 31, 2012 are as follows:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities - other	**29,645**	30,414
Pensions, PBOP and other employee benefits	**29,558**	31,657
Future federal benefit on state taxes	**8,490**	8,120
Other deferred tax assets	**5,254**	7,945
Total deferred tax assets [(1)]	**72,947**	78,136
Deferred tax liabilities:		
Property related differences	**112,020**	104,011
Regulatory assets - merger savings	**89,896**	92,835
Regulatory assets - Pensions and PBOP	**16,249**	21,997
Other items	**5,243**	4,349
Total deferred tax liabilities	**223,408**	223,192
Net deferred income tax liability	**150,461**	145,056
Deferred investment tax credit	**250**	453
Net deferred income tax liability and investment tax credit	**150,711**	145,509
Current portion of net deferred income tax assets	**25,129**	36,205
Non-current deferred income tax liability	**$ 175,840**	$ 181,714

[(1)] There were no valuation allowances for deferred tax assets at March 31, 2013 or March 31, 2012.

The Company is a member of the NGNA and subsidiaries' consolidated federal income tax return. The Company has joint and several liability for any potential assessments against the consolidated group.

As of March 31, 2013 and March 31, 2012, the Company's current federal income taxes balances payable to its parent are $13.5 million and $12.5 million, respectively.

Unrecognized Tax Benefits

As of March 31, 2013 and March 31, 2012, the Company's unrecognized tax benefits totaled $16.1 million and $15.4 million, respectively, of which none would affect the effective tax rate, if recognized.

The following table reconciles the changes to the Company's unrecognized tax benefits for the years ended March 31, 2013 and March 31, 2012:

Reconciliation of unrecognized tax benefits	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Balance at the beginning of the year	**$ 15,418**	$ 14,568
Gross increases related to prior period	**-**	635
Gross decreases related to prior period	**(58)**	(179)
Gross increases related to current period	**829**	394
Gross decreases related to current period	**(105)**	-
Balance at the end of the year	**$ 16,084**	$ 15,418

As of March 31, 2013 and March 31, 2012, the Company has accrued for interest related to unrecognized tax benefits of $2.6 million and $2.1 million, respectively. During the years ended March 31, 2013 and March 31, 2012, the Company recorded interest expense of $0.5 million and $0.2 million, respectively. The Company recognizes accrued interest related to unrecognized tax benefits in interest expense, interest income and related penalties, if applicable, in other deductions in the accompanying statements of income. No penalties were recognized during the years ended March 31, 2013 and March 31, 2012.

It is reasonably possible that other events will occur during the next 12 months that would cause the total amount of unrecognized tax benefits to increase or decrease. However, the Company does not believe any such increases or decreases would be material to its results of operations, financial position, or liquidity

In September 2011, the Internal Revenue Service ("IRS") commenced an audit of KeySpan Corporation and subsidiaries for the short year ended August 24, 2007 and NGNA and subsidiaries for the years ending March 31, 2008 and March 31, 2009. The years ended March 31, 2010 through March 31, 2013 remain subject to examination by the IRS.

The Company is a member of the NGUSA Service Company Massachusetts unitary group since the year ended March 31, 2010. The tax returns for the years ended March 31, 2010 through March 31, 2013 remain subject to examination by the State of Massachusetts.

The following table indicates the earliest tax year subject to examination:

Jurisdiction	**Tax Year**
Federal	August 24, 2007
Massachusetts	March 31, 2010

Note 8. Debt

Senior Notes

In March 2012, the Company issued $50 million of unsecured long-term debt in two tranches through private placement. The Company issued $25 million of 10 year unsecured bonds at a coupon rate of 3.296% and an additional $25 million of 30 year unsecured bonds at a coupon rate of 4.628%. The aggregate debt is not registered under the U.S. Securities Act of 1933 ("Securities Act") and was sold in the United States only to accredited investors in reliance on Section 4(2) of the Securities Act. The proceeds from the financing were used to pay off the advance from parent of $49 million (see below), and the balance of the proceeds was used for ongoing working capital needs.

First Mortgage Bonds

The assets of the Company are subject to liens and other charges and are provided as collateral over borrowings of $75 million of non-callable FMB. The Company's FMB indenture includes, among other provisions, limitations on the issuance of long-term debt.

Advance from Affiliates

At March 31, 2011, the Company had $49 million of advances payable due to KNE LLC. In March 2012, the Company issued $50 million of unsecured senior long-term notes, the proceeds of which were used to repay the existing debt from parent of $49 million.

The aggregate maturities of long-term debt subsequent to March 31, 2013 are as follows:

(in thousands of dollars) Years Ending March 31,	
2014	$ -
2015	-
2016	-
2017	-
2018	-
Thereafter	125,000
Total	$ 125,000

The Company is obligated to meet certain financial and non-financial covenants. During the years ended March 31, 2013 and March 31, 2012, the Company was in compliance with all such covenants.

Note 9. Goodwill

The following table represents the changes in the carrying amount of goodwill for the years ended March 31, 2013 and March 31, 2012:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Goodwill, beginning of year	**$ 54,564**	$ 54,564
Adjustments for recovery of acquisition premium	**(490)**	-
Goodwill, end of year	**$ 54,074**	$ 54,564

The net adjustments of ($0.5) million shown in the table above include: (1) a reclassification adjustment of $5.5 million from regulatory assets to goodwill in order to correct these balances and properly reflect the authorized recovery period of acquisition premium under DPU 10-55, and (2) a reclassification adjustment of ($6.0) million from goodwill to regulatory assets related to the DPU's January 2013 ruling, as described below.

The Company was acquired by Eastern in 1998 pursuant to a business combination transaction ("the Eastern Merger"). Subsequent to the Eastern Merger, the Company and Eastern entered into business combinations with KeySpan in 2000 and then with NGUSA in 2007. In 1998, Eastern and the Company applied with the Massachusetts Department of Telecommunications and Energy ("DTE") for recovery of acquisition premium incurred during the Eastern Merger. The amount of acquisition premium related to the merger was approximately $246.0 million ($149.5 million, net of tax). The Company and Eastern agreed to a ten-year rate freeze as well as reduction of the price of burner-tip gas for customers as a required condition for the recovery of acquisition premium over the course of a 30 year recovery period ending in August 2039. Further, pursuant to DTE 98-128, the recovery of acquisition premium was contingent upon substantiated proof of merger savings achieved.

On November 1, 2010, the DPU issued DPU 10-55 which authorized the recovery of $234.8 million of goodwill ($141.5 million of acquisition premium, plus tax of $93.3 million). During the year ended March 31, 2011, the Company recorded a regulatory asset of $234.8 million, along with corresponding credits to a newly created deferred tax liability of $93.3 million and a reclassification of $141.5 million to reduce goodwill.

In November 2010, the Company filed a Motion for Reconsideration with the DPU for approval to recover the remaining unrecovered acquisition premium. On January 31, 2013, the DPU ruled that the Company was able to demonstrate that it had fully achieved the merger savings related to its 1998 acquisition, and granted recovery of the remaining unrecovered acquisition premium. As a result, the Company recorded adjustments to the previously-established regulatory asset, deferred tax liability, and goodwill balances. The regulatory asset for the recovery of the acquisition premium was $216.6 million at March 31, 2013, and will be amortized on a straight-line basis as it is recovered through rates at $8.2 million per year through August 2039.

Note 10. Commitments and Contingencies

Gas Purchase and Capital Expenditure Commitments

The Company has entered into various contracts for gas delivery, storage and supply services. Certain of these contracts require payment of annual demand charges. The Company is liable for these payments regardless of the level of services required from third parties. Such charges are currently recovered from customers as gas costs. In addition, the Company has various capital commitments related to the construction of property, plant and equipment.

The Company's commitments under these long-term contracts for years subsequent to March 31, 2013 are summarized in the table below:

(in thousands of dollars) Years Ending March 31,	Gas	Capital Expenditure
2014	$ 40,782	$ 4,607
2015	27,818	10,579
2016	14,305	-
2017	12,477	-
2018	11,326	-
Thereafter	35,357	-
Total	$ 142,065	$ 15,186

Asset Retirement Obligations

The Company has various asset retirement obligations associated with its gas distribution facilities. Generally, the Company's largest asset retirement obligations relate to: (i) legal requirements to cut (disconnect from the gas distribution system), purge (clean of natural gas and PCB contaminants) and cap gas mains within the Company's gas distribution and transmission system when mains are retired in place; or dispose of sections of gas main when removed from the pipeline system; (ii) cleaning and removal requirements associated with storage tanks containing waste oil and other waste contaminants; and (iii) legal requirements to remove asbestos upon major renovation or demolition of structures and facilities.

The following table represents the changes in the asset retirement obligations for the years ended March 31, 2013 and March 31, 2012:

	March 31	
	2013	2012
	(in thousands of dollars)	
Balance as of beginning of year	**$ 2,076**	$ 1,958
Accretion expense	**125**	118
Balance as of end of year	**$ 2,201**	$ 2,076

Sales and Use Tax

The Company is subject to periodic tax audits by federal and state authorities. In 2007, the State of Massachusetts commenced a sales and use tax audit for the September 2003 through December 2005 period. At March 31, 2012, the Company had recorded a reserve of $0.5 million relative to this matter, and this audit was settled in April 2012 consistent with that amount. The sales and use tax audit for 2006 and subsequent years remain subject to examination by the state authorities, and in 2013, the state commenced a sales and use tax audit for the January 2006 through December 2010 period. As of March 31, 2013, the Company has not established a reserve for the current audit cycle.

Legal Matters

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

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.

Within the Commonwealth of Massachusetts, the Company is aware of numerous former MGP sites and related facilities within the existing or former service territories of the Company. Investigation and remediation expenditures incurred for the years ended March 31, 2013 and March 31, 2012 were $0.4 million and $0.5 million, respectively.

Upon the acquisition of KeySpan by NGUSA, the Company recognized 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 of KeySpan by NGUSA, these liabilities are recognized in accordance with the current accounting guidance for environmental liabilities. The Company estimated the remaining costs of environmental remediation activities were $6.0 million and $6.2 million at March 31, 2013 and March 31, 2012, respectively. The Company's environmental obligation is discounted at a rate of 6.5%: the undiscounted amount of environmental liabilities at March 31, 2013 and March 31, 2012 was $7.0 million and $7.4 million, respectively. These costs are expected to be incurred over the next 33 years, and the discounted amounts have been recorded as reserves in the accompanying balance sheets. 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 has recovered amounts from certain insurers, and, where appropriate, the Company may seek recovery from other insurers and from other potentially responsible parties, but it is uncertain whether, and to what extent, such efforts will be successful.

By rate orders, the DPU has provided for the recovery of site investigation and remediation costs. Accordingly, as of March 31, 2013 and March 31, 2012, the Company has recorded environmental regulatory assets of $3.9 million and $4.1 million, respectively.

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

Note 11. Related Party Transactions

Accounts Receivable from Affiliates and Accounts Payable to Affiliates

NGUSA and its affiliates provide various services to the Company, including executive and administrative, customer services, financial (including accounting, auditing, risk management, tax, and treasury/finance), human resources, information technology, legal and strategic planning that are charged between the companies and charged to each company.

The Company records short-term payables to and receivables from certain of its affiliates in the ordinary course of business. The amounts payable to and receivable from its affiliates do not bear interest and are settled through the money pool.

At March 31, 2013 and March 31, 2012, the Company had net outstanding accounts receivable from affiliates/accounts payable to affiliates balances as follows:

	Accounts Receivable from Affiliates		Accounts Payable to Affiliates	
	March 31, 2013	March 31, 2012	March 31, 2013	March 31, 2012
	(in thousands of dollars)			
NGUSA Service Company	$ -	$ -	$ 20,568	$ 2,125
Boston Gas Company	8,019	-	-	-
KeySpan Corporate Service	-	-	-	13,770
Transgas Inc.	3,920	3,252	-	-
KeySpan Corporation	-	-	17,951	21,013
Narragansett Electric Co.	-	-	11,440	-
Other	1	533	946	1,613
	$ 11,940	$ 3,785	$ 50,905	$ 38,521

At March 31, 2013 and March 31, 2012, the non-current portion of accounts receivable from affiliates represents the PBOP liability of approximately $19.0 million allocated to various affiliated entities as disclosed in Note 3, “Employee Benefits”.

Money Pool

The settlement of the Company’s various transactions with NGUSA and certain affiliates generally occurs via the money pool. As of November 1, 2012, NGUSA and its affiliates established a new Regulated Money Pool and an Unregulated Money Pool. Financing for the Company’s working capital and gas inventory needs are obtained through participation in the Regulated Money Pool. The Company, as a participant in the Regulated Money Pool, can both borrow and lend funds. Borrowings from the Regulated and Unregulated Money Pools bear interest in accordance with the terms of the applicable money pool agreement.

The Regulated and Unregulated Money Pools are funded by operating funds from participants in the applicable Pool. Collectively, NGUSA and its subsidiary, KeySpan have the ability to borrow up to $3 billion from National Grid plc for working capital needs including funding of the Money Pools, if necessary. The Company had a short-term money pool receivable of $12.7 million and $20.2 million at March 31, 2013 and March 31, 2012, respectively. The average interest rate for the money pool was approximately 1.4% and 1.2% for the years ended March 31, 2013 and March 31, 2012, respectively.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at their cost. The service company costs are generally allocated to associated companies through a tiered approach. First and foremost, costs are directly charged to the benefited company whenever practicable. Secondly, in cases where direct charging cannot be readily determined, costs are typically allocated using cost/causation principles linked to the relationship of that type of service, such as number of employees, number of customers/meters, capital expenditures, value of property owned, total transmission and distribution expenditures. Lastly, all other costs are allocated based on a general allocator.

Charges from the service companies of NGUSA to the Company for the years ended March 31, 2013 and March 31, 2012 were $45.3 million and $40.1 million, respectively.

Holding Company Charges

NGUSA received charges from National Grid Commercial Holdings Limited, an affiliated company in the UK, for certain corporate and administrative services provided by the corporate functions of National Grid plc to its US subsidiaries. These charges, which are recorded on the books of NGUSA, have not been reflected on these financial statements. Were these amounts allocated to the Company, the estimated effect on net income would be $0.8 million before taxes, and $0.5 million after taxes, for each of the years ended March 31, 2013 and March 31, 2012.