New Jersey Natural Gas

2013 ANNUAL REPORT

NEW JERSEY NATURAL GAS

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INDEX

Deloitte & Touche LLP
100 Kimball Drive
Parsippany, NJ 07054
USA
Tel: +1 973 602-6000
Fax: +1 973 602-5050
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
New Jersey Natural Gas Company

We have audited the accompanying financial statements of New Jersey Natural Gas Company (the "Company"), which comprises the balance sheets as of September 30, 2013 and 2012, and the related statements of operations, common stock equity, and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these 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.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 the auditor’s 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, the auditor considers 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 New Jersey Natural Gas Company as of September 30, 2013 and 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.

Deloitte & Touche LLP

December 20, 2013

New Jersey Natural Gas Company

STATEMENTS OF OPERATIONS

(Thousands)

Fiscal years ended September 30,		**2013**		2012
OPERATING REVENUES	**$**	**787,987**	$	627,713
OPERATING EXPENSES				
Gas purchases		**414,594**		274,370
Operation and maintenance		**113,174**		111,998
Regulatory rider expenses		**48,417**		40,350
Depreciation and amortization		**37,999**		35,247
Energy and other taxes		**52,410**		41,140
Total operating expenses		**666,594**		503,105
OPERATING INCOME		**121,393**		124,608
Other income		**2,847**		1,655
Interest charges, net of capitalized interest		**14,995**		14,890
INCOME BEFORE INCOME TAXES		**109,245**		111,373
Income tax provision		**35,399**		38,135
NET INCOME	**$**	**73,846**	$	73,238

See Notes to Financial Statements

New Jersey Natural Gas Company

STATEMENTS OF CASH FLOWS

(Thousands)		
Fiscal years ended September 30,	**2013**	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	**$ 73,846**	$ 73,238
Adjustments to reconcile net income to cash flows from operating activities:		
Depreciation and amortization	**37,999**	35,247
Allowance for funds used during construction	**(2,037)**	(638)
Amortization of deferred charges	**763**	726
Allowance for bad debt expense	**2,446**	2,334
Deferred income taxes	**29,817**	23,276
Manufactured gas plant remediation costs	**(6,166)**	(7,965)
Cost of removal – asset retirement obligation	**(1,697)**	(1,196)
Contributions to postemployment benefit plans	**(25,930)**	(25,775)
Changes in:		
Components of working capital	**(9,815)**	(47,624)
Other noncurrent assets	**8,677**	(14,679)
Other noncurrent liabilities	**(1,542)**	21,311
Cash flows from operating activities	**106,361**	58,255
CASH FLOWS (USED IN) INVESTING ACTIVITIES		
Expenditures for		
Utility plant	**(110,482)**	(104,277)
Cost of removal	**(26,601)**	(12,178)
Withdrawal from (investment in) restricted cash construction fund	**56**	(802)
Cash flows (used in) investing activities	**(137,027)**	(117,257)
CASH FLOWS FROM FINANCING ACTIVITIES		
Payments of common stock dividends to parent	**(49,979)**	(47,328)
Tax benefit from stock options exercised	**52**	73
Proceeds from long-term debt	**50,000**	—
Payments of long-term debt	**(8,916)**	(8,025)
Proceeds from short-term debt, net of payments	**33,600**	108,500
Proceeds from sale-leaseback transaction	**7,076**	6,522
Cash flows from financing activities	**31,833**	59,742
Change in cash and cash equivalents	**1,167**	740
Cash and cash equivalents at beginning of period	**745**	5
Cash and cash equivalents at end of period	**$ 1,912**	$ 745
CHANGES IN COMPONENTS OF WORKING CAPITAL		
Receivables	**$ (12,188)**	$ 10,174
Inventories	**33,954**	13,511
Recovery of gas costs	**6,100**	(11,686)
Accounts payable and other	**1,513**	6,277
Gas purchases payable	**6,264**	(7,848)
Prepaid and accrued taxes, net	**(14,694)**	14,920
Customers' credit balances and deposits	**(24,112)**	(65,254)
Restricted broker margin accounts	**1,500**	10,009
Other current assets	**(8,152)**	(17,727)
Total	**$ (9,815)**	$ (47,624)
SUPPLEMENTAL DISCLOSURES OF CASH FLOWS INFORMATION		
Cash paid for		
Interest (net of amounts capitalized)	**$ 12,498**	$ 12,407
Income taxes	**$ 22,257**	$ 8,179
SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING ACTIVITIES		
Accrued capital expenditures	**$ 259**	$ (2,392)

See Notes to Financial Statements

New Jersey Natural Gas Company

BALANCE SHEETS

ASSETS

(Thousands)		
September 30,	**2013**	2012
PROPERTY, PLANT AND EQUIPMENT		
Utility plant, at cost	**$ 1,681,585**	$ 1,591,532
Construction work in progress	**114,961**	102,420
Total property, plant and equipment	**1,796,546**	1,693,952
Accumulated depreciation and amortization	**(383,895)**	(402,308)
Property, plant and equipment, net	**1,412,651**	1,291,644
CURRENT ASSETS		
Cash and cash equivalents	**1,912**	745
Customer accounts receivable:		
Billed	**43,045**	33,093
Unbilled	**7,429**	7,017
Allowance for doubtful accounts	**(5,287)**	(4,665)
Regulatory assets	**34,372**	32,734
Gas in storage, at average cost	**104,979**	145,379
Materials and supplies, at average cost	**13,007**	6,561
Prepaid taxes	**40,300**	25,515
Derivatives, at fair value	**3,502**	6,203
Broker margin account	**213**	1,713
Other	**10,050**	7,730
Total current assets	**253,522**	262,025
NONCURRENT ASSETS		
Regulatory assets	**402,202**	441,263
Derivatives, at fair value	**121**	1,000
Other	**33,313**	9,588
Total noncurrent assets	**435,636**	451,851
Total assets	**$ 2,101,809**	$ 2,005,520

See Notes to Financial Statements

New Jersey Natural Gas Company

CAPITALIZATION AND LIABILITIES

(Thousands, except for share data)

September 30,	2013	2012
CAPITALIZATION		
Common stock, $5 par value; authorized 4,750,000 shares; outstanding 3,214,923 shares	**$ 16,075**	$ 16,075
Premium on common stock	**11,269**	11,269
Contribution from parent and other	**359,099**	359,047
Retained earnings	**311,470**	287,603
Common stock equity	**697,913**	673,994
Long-term debt	**362,886**	375,169
Total capitalization	**1,060,799**	1,049,163
CURRENT LIABILITIES		
Current maturities of long-term debt	**68,643**	7,760
Short-term debt	**168,600**	135,000
Gas purchases payable	**30,744**	24,480
Accounts payable and other	**39,239**	38,046
Deferred and accrued taxes	**9,276**	1,101
Regulatory liabilities	**1,456**	1,169
New Jersey clean energy program	**14,532**	5,619
Derivatives, at fair value	**2,045**	5,034
Customers’ credit balances and deposits	**24,256**	48,368
Total current liabilities	**358,791**	266,577
NONCURRENT LIABILITIES		
Deferred income taxes	**333,046**	310,452
Deferred investment tax credits	**5,584**	5,905
Derivatives, at fair value	**140**	—
Manufactured gas plant remediation	**183,600**	182,000
Postemployment benefit liability	**47,278**	91,530
Regulatory liabilities	**79,647**	67,077
Asset retirement obligation	**28,711**	27,983
Other	**4,213**	4,833
Total noncurrent liabilities	**682,219**	689,780
Total capitalization and liabilities	**$ 2,101,809**	$ 2,005,520

See Notes to Financial Statements

STATEMENTS OF COMMON STOCK EQUITY

(Thousands)	Number of Shares	Common Stock	Premium on Common Stock	Contribution from Parent and Other	Retained Earnings	Total
Balance at September 30, 2011	3,215	$ 16,075	$ 11,269	$ 358,974	$ 261,693	$ 648,011
Net income					73,238	73,238
Tax benefit from stock plans				73		73
Cash dividend declared					(47,328)	(47,328)
Balance at September 30, 2012	3,215	16,075	11,269	359,047	287,603	673,994
Net income					**73,846**	**73,846**
Tax benefit from stock plans				**52**		**52**
Cash dividend declared					**(49,979)**	**(49,979)**
Balance at September 30, 2013	**3,215**	**$ 16,075**	**$ 11,269**	**$ 359,099**	**$ 311,470**	**$ 697,913**

See Notes to Financial Statements

1. NATURE OF THE BUSINESS

New Jersey Natural Gas (the Company) is a local natural gas distribution company that provides regulated retail natural gas service to approximately 497,400 residential and commercial customers in central and northern New Jersey, and participates in the off-system sales and capacity release markets. The Company is the regulated utility subsidiary of New Jersey Resources Corporation (NJR) and is subject to rate regulation by the New Jersey Board of Public Utilities (BPU). The Company owns approximately 6,990 miles of distribution main, 7,000 miles of service main, 226 miles of transmission main and approximately 518,000 meters. Mains are primarily located under public roads. Where mains are located under private property, the Company has obtained easements from the owners of record.

Additionally, the Company owns and operates two LNG storage plants in Stafford Township, Ocean County; and Howell Township, Monmouth County. The two LNG plants have an aggregate estimated maximum capacity of approximately 170,000 dths per day and 1 Bcf of total capacity. These facilities are used for peaking natural gas supply and emergencies.

The Company owns four service centers located in Rockaway Township, Morris County; Atlantic Highlands and Wall Township, Monmouth County; and Lakewood, Ocean County. These service centers house storerooms, garages, gas distribution and administrative offices. The Company leases its headquarters and customer service facilities in Wall Township, Monmouth County, a customer service office in Asbury Park, Monmouth County and a service center in Manahawkin, Ocean County. These customer service offices support customer contact, marketing, economic development and other functions.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulatory Assets & Liabilities

Under cost-based regulation, regulated utility enterprises generally are permitted to recover their operating expenses and earn a reasonable rate of return on their utility investment.

The Company maintains its accounts in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts as prescribed by the BPU and in accordance with the *Regulated Operations* Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC). As a result of the impact of the ratemaking process and regulatory actions of the BPU, the Company is required to recognize the economic effects of rate regulation. Accordingly, the Company capitalizes or defers certain costs that are expected to be recovered from its customers as regulatory assets and recognizes certain obligations representing probable future expenditures as regulatory liabilities on the Balance Sheets. See *Note 3. Regulation,* for a more detailed description of the Company's regulatory assets and liabilities.

Gas in Storage

Gas in storage is reflected at average cost on the Balance Sheets, and represents natural gas and liquefied natural gas that will be utilized in the ordinary course of business. The Company had 20.4 billion cubic feet (Bcf) and 22.2 Bcf of gas in storage as of September 30, 2013 and 2012, respectively.

Demand Fees

For the purpose of securing adequate storage and pipeline capacity, the Company enters into storage and pipeline capacity contracts, which require the payment of certain demand charges to maintain the ability to access such natural gas storage or pipeline capacity, during a fixed time period, which generally ranges from one to five years. Demand charges are based on established rates as regulated by FERC. These demand charges represent commitments to pay storage providers or pipeline companies for the right to store and transport natural gas utilizing their respective assets. Demand fees of $92.1 million and $86.7 million for fiscal years ended September 30, 2013 and 2012, respectively, which are net of fees received for capacity release, are included in its weighted average cost of gas. The demand charges are expensed as a component of gas purchases in the Statements of Operations based on Basic Gas Supply Service (BGSS) sales and recovered as part of its gas commodity component of its BGSS tariff.

Derivative Instruments

Derivative instruments associated with natural gas commodity contracts are recorded in accordance with the *Derivatives and Hedging* Topic of the ASC 815, under which the Company records the fair value of derivatives, held as assets and liabilities. The Company's derivatives used to economically hedge its natural gas purchasing activities are recoverable through its BGSS, a component of its tariff. Accordingly, the offset to the change in fair value of these derivatives is recorded as a Regulatory asset or liability on the Balance Sheets.

See *Note 4. Derivative Instruments* for additional details regarding natural gas transacting activities.

Fair values of exchange-traded instruments, including futures, swaps and certain options, are based on actively quoted market prices. Fair values are subject to change in the near term and reflect management's best estimate based on various factors. In establishing the fair value of commodity contracts that do not have quoted prices, such as physical contracts, and over-the-counter options and swaps, and certain embedded derivatives, management uses available market data and pricing models to estimate fair values. Estimating fair values of instruments that do not have quoted market prices requires management's judgment in determining amounts, which could reasonably be expected to be received from, or paid to, a third party in settlement of the instruments. These amounts could be materially different from amounts that might be realized in an actual sale transaction.

Revenues

Revenues from the sale of natural gas to customers of the Company are recognized in the period that gas is delivered and consumed by customers, including an estimate for unbilled revenue.

In determining the amount of revenue from sales to natural gas customers by the Company, certain assumptions are used to develop estimates of unaccounted-for gas. Unaccounted-for gas occurs for a number of reasons including leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants. The estimating factors may change from time to time as a result of improvements in the quality and/or the timeliness of certain metering and billing information.

The Company records unbilled revenue for natural gas services. Natural gas sales to individual customers are based on meter readings, which are performed on a systematic basis throughout the month. At the end of each month, the amount of natural gas delivered to each customer after the last meter reading is estimated, and the Company recognizes unbilled revenues related to these amounts. The unbilled revenue estimates are based on amounts delivered from date of the last meter read to the end of the respective accounting period, estimated customer usage by customer type, weather effects, unaccounted-for gas and the most current tariff rates.

Gas Purchases

The Company's tariff includes a component for BGSS, which is designed to allow the Company to recover the cost of natural gas through rates charged to its customers and is typically revised on an annual basis. As part of computing its BGSS rate, the Company projects its cost of natural gas, net of supplier refunds, the impact of hedging activities and credits from non-firm sales and transportation activities. The Company subsequently recovers or refunds the difference, if any, of actual costs compared with those included in current rates. Any underrecoveries or overrecoveries are either refunded to customers or deferred and, subject to BPU approval, reflected in the BGSS rates in subsequent years.

Income Taxes

The Company computes income taxes using the liability method, whereby deferred income taxes are generally determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect in the years in which the differences are expected to reverse. See *Note 9. Income Taxes.*

Investment tax credits (ITCs) have been deferred and are being amortized as a reduction to the tax provision over the average lives of the related equipment in accordance with regulatory treatment.

Capitalized and Deferred Interest

Included on the Balance Sheets are capitalized amounts associated with the debt and equity components of the Company's allowance for funds used during construction (AFUDC), which are recorded in utility plant. The Company's base rates include the ability for the Company to recover the cost of debt associated construction work in progress (CWIP). For most of the Company's construction projects, an incremental cost of equity is also recoverable during periods when the Company's short-term debt balances are lower than its CWIP. Corresponding amounts recognized in interest expense and other income, as appropriate, are included in the Statements of Operations for the fiscal years ended September 30, are as follows:

($ in thousands)	**2013**	2012
AFUDC:		
Debt	**$ 921**	$ 300
Equity	**2,037**	638
Total	**$ 2,958**	$ 938
Weighted average interest rate	**1.05%**	1.47%

Pursuant to a BPU order, the Company is permitted to recover carrying costs on uncollected balances related to Societal Benefits Clause (SBC) program costs, which include New Jersey Clean Energy Program (NJCEP), Remediation Adjustment (RA) and Universal Service Fund (USF) expenditures. See *Note 3. Regulation*. The SBC interest rate changes each September based on the August 31 seven-year constant maturity Treasury rate plus 60 basis points. The rate was 2.84 percent and1.61 percent for the fiscal years ended September 30, 2013 and 2012, respectively. Accordingly, other income included $653,000 and $878,000 for the fiscal years ended September 30, 2013 and 2012, respectively.

Sales Tax Accounting

Sales tax and Transitional Energy Facilities Assessment (TEFA) are collected from customers and presented in both operating revenues and operating expenses on the Statements of Operations for the fiscal years ended September 30, as follows:

(Millions)	**2013**	2012
Sales tax	**$ 43.0**	$ 31.3
TEFA (1)	**5.0**	6.0
Total	**$ 48.0**	$ 37.3

(1) TEFA will be phased out over a three-year period commencing January 1, 2012.

Cash and Cash Equivalents

Cash and cash equivalents consists of cash on deposit and temporary investments with original maturities of three months or less, and excludes restricted cash of $1.1 million and $1.2 million as of September 30, 2013 and 2012, respectively, related to escrow balances for utility plant projects, which are recorded in other noncurrent assets on the Balance Sheets.

Property Plant and Equipment

Regulated property, plant and equipment is stated at original cost. Costs include direct labor, materials and third-party construction contractor costs, AFUDC and certain indirect costs related to equipment and employees engaged in construction. Upon retirement, the cost of depreciable regulated property, plus removal costs less salvage, is charged to accumulated depreciation with no gain or loss recorded.

Depreciation is computed on a straight-line basis over the useful life of the assets for financial statement purposes and using rates based on the estimated average lives of the various classes of depreciable property for the Company. The composite rate of depreciation used was 2.43 percent of average depreciable property in fiscal 2013 and 2.38 percent in fiscal 2012.

Property, plant and equipment was comprised of the following as of September 30, 2013 and 2012:

(Thousands) **Property Classifications**	**Estimated Useful Lives**	**2013**	2012
Distribution facilities	38 to 74 years	**$ 1,421,885**	$ 1,352,101
Transmission facilities	35 to 56 years	**273,853**	248,774
Storage facilities	34 to 47 years	**41,687**	41,663
All other property	5 to 35 years	**59,121**	51,414
Total property, plant and equipment		**1,796,546**	1,693,952
Accumulated depreciation and amortization		**(383,895)**	(402,308)
Property, plant and equipment, net		**$ 1,412,651**	$ 1,291,644

Impairment of Long-Lived Assets

The Company reviews the carrying amount of an asset for possible impairment whenever events or changes in circumstances indicate that such amount may not be recoverable.

No impairments were identified for the fiscal years ended September 30, 2013 and 2012.

Customer Accounts Receivable and Allowance for Doubtful Accounts

The Company's receivables consist of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. The Company evaluates its accounts receivable and, to the extent customer account balances are outstanding for more than sixty days, establishes an allowance for doubtful accounts. The allowance is based on a combination of factors including historical collection experience and trends, aging of receivables, general economic conditions in the company's distribution or sales territories, and customer specific information. The Company writes-off customers' accounts once it is determined they are uncollectible.

Loans Receivable

The Company provides interest-free loans, with terms ranging from two to ten years, to customers that elect to purchase and install certain energy efficient equipment in accordance with its BPU approved SAVEGREEN program. The loans are recognized at net present value on the Balance Sheets. Refer to *Note 5. Fair Value* for a discussion of the Company's fair value measurement policies and level disclosures. As of September 30, 2013, the Company has recorded $1.9 million in other current assets and $14.3 million in other noncurrent assets on the Balance Sheets. As of September 30, 2012, the Company recorded $6.8 million related to the loans.

The Company's policy is to establish an allowance for doubtful accounts when loan balances are outstanding for more than sixty days. During fiscal 2013 and 2012 there was no allowance for doubtful accounts established related to loans receivable.

Asset Retirement Obligations (ARO)

The Company recognizes a liability for its AROs based on the fair value of the liability when incurred, which is generally upon acquisition, construction, development and/or through the normal operation of the asset. Concurrently, the Company also capitalizes an asset retirement cost by increasing the carrying amount of the related asset by the same amount as the liability. In periods subsequent to the initial measurement, the Company is required to recognize changes in the liability resulting from the passage of time (accretion) or due to revisions to either timing or the amount of the originally estimated cash flows to settle the conditional ARO.

Pension and Postemployment Plans

The Company has two noncontributory defined pension plans covering substantially all employees, including officers. Benefits are based on each employee's years of service and compensation. The Company's funding policy is to contribute annually to these plans at least the minimum amount required under the Employee Retirement Income Security Act (ERISA) of 1974, as amended, and not more than can be deducted for federal income tax purposes. Plan assets consist of equity securities, fixed-income securities and short-term investments. In fiscal 2013 and 2012, the Company had no minimum funding requirements however the Company made discretionary contributions to the pension plans of $20 million in aggregate to the plans in fiscal 2013 and 2012.

The Company also provides two primarily noncontributory medical and life insurance plans for eligible retirees and dependents. Medical benefits, which make up the largest component of the plans, are based upon an age and years-of-service vesting schedule and other plan provisions. Funding of these benefits is made primarily into Voluntary Employee Beneficiary Association trust funds. The Company contributed $6 million and $5.8 million in aggregate to these plans in fiscal 2013 and 2012, respectively.

Recent Updates to the Accounting Standards Codification (ASC)

Balance Sheet Offsetting

In December 2011, the FASB issued ASU No. 2011-11, an amendment to ASC Topic 210, *Balance Sheet*, requiring additional disclosures about the nature of an entity's rights of setoff and related master netting arrangements associated with its financial and derivative instruments. The objective of the disclosures is to facilitate comparison between financial statements prepared on the basis of U.S. GAAP and those prepared on the basis of IFRS. The amended guidance will become effective for annual periods beginning on or after January 1, 2013, and will be applied retrospectively. The Company believes that there will be no impact to the financial position, results of operations or cash flows upon adoption.

Income Taxes

In July 2013, the FASB issued ASU No. 2013-11, an amendment to ASC Topic 740, *Income Taxes*, which clarifies financial statement presentation for unrecognized tax benefits. The ASU requires that an unrecognized tax benefit, or portion thereof, shall be presented in the balance sheet as a reduction to a deferred tax asset for a net operating loss carryforward, similar tax loss or a tax credit carryforward. To the extent such a deferred tax asset is not available or the company does not intend to use it to settle any additional taxes that would result from the disallowance of a tax position, the related unrecognized tax benefit will be presented as a liability in the financial statements. The amended guidance will become effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. As of September 30, 2013, the Company does not have any unrecognized tax benefits, however, it will apply the provisions of the new guidance, as applicable at the effective date, on a prospective basis.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires the Company to make estimates that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosure of contingencies during the reporting period. On a monthly basis, the Company evaluates its estimates, including those related to the calculation of the fair value of derivative instruments, unbilled revenues, allowance for doubtful accounts, provisions for depreciation and amortization, regulatory assets and liabilities, income taxes, pensions and other postemployment benefits, contingencies related to environmental matters and litigation and asset retirement obligations, which are evaluated on an annual basis. The Company bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources.

The Company has legal, regulatory and environmental proceedings during the normal course of business which can result in loss contingencies. When evaluating the potential for a loss, the Company will establish a reserve if a loss is probable and can be estimated, in which case it is the Company's policy to accrue the full amount of such estimate. Where the information is sufficient only to establish a range of probable liability, and no point within the range is more likely than any other, it is the Company's policy to accrue the lower end of the range. In the normal course of business, estimated amounts are subsequently adjusted to actual results that may differ from estimates.

Subsequent Events

To the best of our knowledge and belief, no other material events have occurred subsequent to September 30, 2013, but before December 20, 2013, the date the financial statements were issued that require consideration as adjustments to or disclosures in the aforementioned financial statements, except as disclosed in *Note 3. Regulation.*

3. REGULATION

The Electric Discount and Energy Competition Act (EDECA) is the legal framework for New Jersey's public utility and wholesale energy landscape. The Company is required, pursuant to a written order by the BPU under EDECA, to open its residential markets to competition from third-party natural gas suppliers. Customers can choose the supplier of their natural gas commodity in the Company's service territory.

As required by EDECA, the Company's rates are segregated into two primary components, the commodity portion, which represents the wholesale cost of natural gas, including the cost for interstate pipeline capacity to transport the gas to the Company's service territory, and the delivery portion, which represents the transportation of the commodity portion through the Company's gas distribution system to the end-use customer. The Company does not earn utility gross margin on the commodity portion of its natural gas sales. The Company earns utility gross margin through the delivery of natural gas to its customers, regardless of whether it or a third-party supplier provides the wholesale natural gas commodity.

Under EDECA, the BPU is required to audit the state's energy utilities every two years. The primary purpose of the audit is to ensure that utilities and their affiliates offering unregulated retail services do not have an unfair competitive advantage over nonaffiliated providers of similar retail services. A combined competitive services and management audit of the Company commenced in August 2013, and a final report is expected to be approved by the BPU in fiscal 2014.

The Company is subject to cost-based regulation, therefore, it is permitted to recover authorized operating expenses and earn a reasonable return on its utility investment based on the BPU's approval, in accordance with accounting guidance applicable to regulated operations. The impact of the ratemaking process and decisions authorized by the BPU allows the Company to capitalize or defer certain costs that are expected to be recovered from its customers as regulatory assets and to recognize certain obligations representing amounts that are probable future expenditures as regulatory liabilities.

As recovery of regulatory assets is subject to BPU approval, if there are any changes in regulatory positions that indicate recovery is not probable, the related cost would be charged to income in the period of such determination.

Regulatory assets and liabilities included on the Balance Sheets as of September 30, are comprised of the following:

(Thousands)		**2013**		2012
Regulatory assets-current				
Underrecovered gas costs	**$**	**953**	$	7,053
Conservation Incentive Program		**18,887**		25,681
New Jersey Clean Energy Program		**14,532**		—
Total current	**$**	**34,372**	$	32,734
Regulatory assets-noncurrent				
Environmental remediation costs				
Expended, net of recoveries	**$**	**46,968**	$	59,745
Liability for future expenditures		**183,600**		182,000
Deferred income and other taxes		**10,718**		11,405
Derivatives, net		**19**		—
SAVEGREEN		**30,004**		26,025
New Jersey Clean Energy Program		—		5,619
Postemployment and other benefit costs		**101,415**		142,495
Deferred Superstorm Sandy costs		**14,822**		—
Other noncurrent assets		**14,656**		13,974
Total noncurrent	**$**	**402,202**	$	441,263
Regulatory liability-current				
Derivatives, net	**$**	**1,456**	$	1,169
Total current	**$**	**1,456**	$	1,169
Regulatory liabilities-noncurrent				
Cost of removal obligation	**$**	**79,315**	$	65,994
Derivatives, net		—		1,000
Other noncurrent liabilities		**332**		83
Total noncurrent	**$**	**79,647**	$	67,077

The Company's recovery of costs is facilitated through its base tariff rates, BGSS and other regulatory tariff riders. The Company is required to make an annual filing to the BPU by June 1 of each year for review of its BGSS, CIP and various other programs and related rates. Annual rate changes are requested to be effective at the beginning of the following fiscal year. In addition, the Company is also permitted to request approval of certain rate or program changes on an interim basis. All rate and program changes are subject to proper notification and BPU review and approval.

Gas Costs

The Company recovers its cost of gas through the BGSS rate component of its customers' bills. The Company's cost of gas includes the purchased cost of the natural gas commodity, fees paid to pipelines and storage facilities, adjustments as a result of BGSS incentive programs, and hedging transactions. Under-recovered gas costs represent a regulatory asset that generally occurs during periods when the Company's BGSS rates are lower than actual costs and requests amounts to be recovered from customers in the future. Conversely, over-recovered gas costs represent a regulatory liability that generally occurs when the Company's BGSS rates are higher than actual costs and requests approval to be returned to customers including interest, when applicable, in accordance with the Company's approved BGSS tariff.

Conservation Incentive Program

The CIP permits the Company to recover utility gross margin variations related to customer usage resulting from customer conservation efforts and allows the Company to mitigate the impact of weather on its gross margin. Such utility gross margin variations are recovered in the year following the end of the CIP usage year, without interest, and are subject to additional conditions, including an earnings test and an evaluation of BGSS related savings.

New Jersey Clean Energy Program

The NJCEP is a statewide program that encourages energy efficiency and renewable energy. Funding amounts are determined by the BPU's Office of Clean Energy and all New Jersey utilities are required to share in the annual funding obligation. The current NJCEP program is for the State of New Jersey's fiscal year ending June 2014. The Company recovers the costs associated with its portion of the NJCEP obligation, including interest, through its SBC rate rider over a one-year period.

Environmental Remediation Costs

The Company is responsible for the cleanup of certain former gas manufacturing facilities. Actual expenditures are recovered from customers, with interest, over seven year rolling periods, through a RA rate rider. Recovery for the Company's estimated future liability will be requested and/or recovered when actual expenditures are incurred. See *Note 10. Commitments and Contingencies*.

Deferred Income Taxes

In 1993, the Company adopted the provisions of *ASC 740, Income Taxes*, which changed the method used to determine deferred tax assets and liabilities. Upon adoption, the Company recognized a transition adjustment and corresponding regulatory asset representing the difference between the Company's existing deferred tax amounts compared with the deferred tax amounts calculated in accordance with the change in method prescribed by ASC 740. The Company recovers the regulatory asset associated with these tax impacts through future base rates, without interest.

Derivatives

Derivatives are utilized by the Company to manage the price risk associated with its natural gas purchasing activities and to participate in certain BGSS incentive programs. The gains and losses associated with the Company's derivatives are recoverable through its BGSS, as noted above, without interest. See *Note 4. Derivatives*.

SAVEGREEN

The Company administers certain programs that supplement the state's NJCEP and that allows the Company to promote clean energy to its residential and commercial customers, as described further below. The Company will recover related expenditures and a weighted average cost of capital through a tariff rider, as approved by the BPU, over a two to ten year period depending upon the specific program incentive.

Postemployment and Other Benefit Costs

Postemployment and Other Benefit Costs represents the Company's underfunded postemployment benefit obligations that the Company began recognizing in fiscal 2006, as a result of changes in the accounting provisions of ASC 715, Compensation and Benefits, as well as a fiscal 2010 tax charge resulting from a change in the deductibility of federal subsidies associated with Medicare D, both of which are deferred as regulatory assets and are recoverable, without interest, in base tariff rates. See *Note 7. Employee Benefit Plans*.

Deferred Superstorm Sandy Costs

In October 2012, portions of the Company's distribution system incurred significant damage as a result of Superstorm Sandy. The Company filed a petition with the BPU in November 2012 requesting deferral accounting for uninsured incremental O&M costs associated with its restoration efforts, which was approved in May 2013. The Company requested that the review of and the appropriate recovery period for such deferred expenses be addressed in the Company's next base rate case to be filed no later than November 15, 2015.

Other Regulatory Assets

Other regulatory assets consists primarily of deferred costs associated with certain components of the Company's SBC, as discussed further below, and the Company's compliance with federal and state mandated pipeline integrity management (PIM) provisions. The Company's related costs to maintain the operational integrity of its distribution and transmission main are recoverable, subject to BPU review and approval, in its next base rate case. The Company is limited to recording a regulatory asset associated with PIM that does not exceed $700,000 per year. In addition, to the extent that project costs are lower than the approved PIM annual expense of $1.4 million, the Company will record a regulatory liability that will be refundable as a credit to customers' gas costs when the net cumulative liability exceeds $1 million. As of September 30, 2013, the Company has recorded $3.2 million of PIM in other regulatory assets.

Cost of Removal Obligation

The Company accrues and collects for cost of removal in base tariff rates on its utility property, without interest. A regulatory liability represents the current collections in excess of actual expenditures, which the Company will return to customers over approximately 48 years, through a reduction in the depreciation expense component of the Company's base tariff rates, as approved by the BPU in the Company's October 2008 base rate case.

The following is a description of regulatory proceedings during fiscal 2012 ***and*** 2013***:***

BGSS and CIP

BGSS rates are normally revised on an annual basis. In addition, in order to manage the fluctuations in wholesale natural gas costs, the Company has the ability to make two interim filings during each fiscal year to increase residential and small commercial customer BGSS rates on a self-implementing and provisional basis. The Company is also permitted to refund or credit back a portion of the commodity costs to customers when the natural gas commodity costs decrease in comparison to amounts projected or to amounts previously collected from customers. During fiscal 2012, the Company provided bill credits of approximately $85.9 million to the Company's residential and small commercial customers due to a decline in the wholesale prices of natural gas and a change in the methodology used to develop estimates of unaccounted-for gas. Commodity prices were relatively stable during fiscal 2013, therefore, no refunds or bill credits were issued to BGSS customers.

Concurrent with the annual BGSS filing, the Company files for an annual review of its CIP. The CIP was initially approved as a three-year program through September 2009. During fiscal 2010, the BPU approved an extension of the program through September 30, 2013. In March 2013, the Company and South Jersey Gas Company filed a joint petition with the BPU requesting the continuation of the CIP with certain modifications. The discovery phase remains in process and since no BPU Order on that petition has been issued as of September 30, 2013, the CIP program will continue for up to one additional year or until such an Order is issued, whichever is earlier. The Company's annual BGSS and CIP filings are summarized as follows:

- June 2011 BGSS/CIP filing - The Company proposed to reduce BGSS rates resulting in a 9.1 percent decrease for the average residential heating customer. The request was the result of cost control and natural gas purchasing strategies, as well as lower natural gas prices. In addition, the Company requested approval to modify its CIP recovery rates resulting in a decrease of $3 million to the total annual recovery. The proposed CIP rates result in an increase to all classes except residential heat, which represents a decrease. In May 2012, the BPU approved the changes on a final basis effective October 2011. In March 2012, the Company notified the BPU that it would reduce its BGSS rate resulting in a 3.6 percent decrease to an average residential heat customer’s bill effective April 1, 2012.

- June 2012 BGSS/CIP filing - The Company proposed to maintain its current BGSS rate. In addition, the Company requested approval to decrease the CIP rate for residential non-heating customers and increase the CIP rates for residential heating and commercial customers, which increased an average residential heating customer bill by 2.4 percent effective October 2012. In May 2013, the BPU approved the changes on a final basis. In May 2013, the Company notified the BPU that it was going to reduce its current BGSS rate resulting in a 5.2 percent decrease to an average residential heat customer's bill, effective June 1, 2013.

- June 2013 BGSS/CIP filing - The Company proposed to maintain its current BGSS rate. In addition, the Company proposed a 1 percent reduction to an average residential heat customer's bill related to the CIP factor. The CIP rate reduction was provisionally approved by the BPU on October 16, 2013, to be effective November 1, 2013.

- On November 21, 2013, the Company notified the BPU of its intent to reduce its BGSS rate, effective December 1, 2013, resulting in a 6 percent decrease to the average residential heating customer bill.

Infrastructure Programs

The Company has significant annual capital expenditures associated with the management of its natural gas distribution and transmission system and its associated PIM program.

During fiscal 2009, the Company implemented its AIP commencing construction on 14 infrastructure projects at a BPU approved cost of $70.8 million, exclusive of AFUDC. AIP was initially approved by the BPU as a two-year program, to enhance the reliability of the Company's gas distribution system and to support economic development and job growth in New Jersey. During fiscal 2012, the BPU approved an extension to the Company's AIP, allowing for additional capital investments of $60.2 million for 9 infrastructure projects, exclusive of AFUDC, to be made through October 2012. The Company was authorized to defer the costs associated with all 23 AIP projects, including the Company's weighted cost of capital and recovers these investments through its base tariff rate.

Annual filings include the following:

- June 2011 AIP filing - The Company filed for AIP base rate cost recovery, which represented an increase of $4.7 million related to AIP infrastructure investments installed in the Company's distribution and transmission systems. A settlement was reached and approved by the BPU effective October 2011. The rate changes included a weighted average cost of capital of 7.12 percent or 7.76 percent depending on the AIP project. The requested base rate change was approved on a final basis in August 2012.

- November 2012 AIP filing - The Company filed for AIP base rate cost recovery, requesting an increase of $6.9 million related to AIP infrastructure investments installed in the Company's distribution and transmission systems through October 2012. The existing weighted average costs of capital remained the same as previously approved. In June 2013, the BPU approved a $6.5 million base rate increase.

In March 2012, the Company filed a petition with the BPU seeking to implement a SAFE program, whereby the Company would invest up to $204 million over a five-year period to replace portions of the Company's gas distribution unprotected steel and cast iron infrastructure in order to improve the safety and reliability of the gas distribution system. The Company entered into a stipulation with the BPU Staff and Rate Counsel, which was approved by the BPU in October 2012, to include a four-year incremental investment program of $130 million, exclusive of AFUDC. The approved SAFE Program includes the deferral of infrastructure costs subject to review in the Company's next base rate case to be filed no later than November 15, 2015, the deferral of depreciation expense on SAFE investments and recognizes an overall rate of return on infrastructure investments of 6.9 percent, including a return on equity of 9.75 percent. The deferred cost recovery will include accruals for both debt and equity components of AFUDC while construction is completed but not yet in service. In accordance with ASC 980, *Regulated Operations*, when SAFE construction projects are placed in service, the Company will accrue an AFUDC debt rate. For ratemaking purposes, subsequent to projects being placed in service, the Company will continue to earn an AFUDC rate of 6.9 percent per year until such time that the Company receives approval for recovery of all costs through base rates.

BGSS Incentive Programs

The Company is eligible to receive financial incentives for reducing BGSS costs through a series of utility gross margin-sharing programs that include off-system sales, capacity release, storage incentive and FRM programs. In August 2011, the BPU approved an extension of the Company's BGSS incentive programs for four years through October 31, 2015, maintaining the existing margin-sharing percentages. This agreement also permits the Company to annually propose a process to evaluate and discuss alternative incentive programs, should performance of the existing incentives or market conditions warrant re-evaluation.

SAVEGREEN

The Company commenced SAVEGREEN during fiscal 2009, allowing it to promote energy efficiency incentives to its residential and commercial customers while stimulating state and local economies through the creation of jobs. Depending on the specific initiative, the Company recovers costs associated with the programs over a two to ten-year period to facilitate home energy audits and to provide financing alternatives, including rebates and other incentives designed to encourage the installation of high efficiency heating and cooling equipment. As of September 30, 2013, the BPU has approved total SAVEGREEN expenditures of $56.4 million related to grants and rebates, of which, the Company has spent a total of $41.1 million and approved $93.1 million related to customer financing incentives, of which, the Company has provided interest-free loans in the amount of $19.4 million.

SAVEGREEN investments and costs are filed with the BPU on an annual basis and include the following:

- June 2011 SAVEGREEN filing - The Company requested through an amended filing in July 2011, that the existing SAVEGREEN rate remain the same as of the original BPU approval in 2009. In January 2012, the BPU approved an extension of SAVEGREEN for one year with an additional $10.4 million of investments in customer incentives and rebates, earning a weighted average cost of capital of 7.1 percent, including a cost of equity of 10.3 percent.

- June 2012 SAVEGREEN filing - In July 2012, the Company filed two petitions with the BPU related to SAVEGREEN. The petitions include the 2012 rate filing, which represents a reconciliation of BPU-approved actual costs for SAVEGREEN and a petition related to the extension of SAVEGREEN over a four-year period, with modifications to include certain new projects. The rate impact will incorporate the existing SAVEGREEN and the extension will include modifications to grants, rebates and financing to be recovered over a two to ten-year period. In June 2013, the BPU approved the filing to extend and expand SAVEGREEN through June 2015, with certain modifications, resulting in a planned investment of approximately $85 million, which includes $17.3 million of investments in grants and rebates, and includes a weighted average cost of capital of 6.9 percent. In addition, the BPU approved a tariff rider rate increase of approximately 1.7 percent to recover costs and investments related to SAVEGREEN over a two to ten-year period, which represents an an annual recovery of approximately $12 million.

Societal Benefits Clause

The SBC is comprised of three primary riders that allow the Company to recover costs associated with USF, which is a permanent statewide program for all natural gas and electric utilities for the benefit of income-eligible customers, MGP remediation, and the NJCEP. The Company has submitted the following filings to the BPU, which includes a report of program expenditures incurred each program year:

- June 2011 USF filing - The Company filed to reduce the annual USF recovery rate, which was approved by the BPU, effective November 2011.

- February 2012 SBC filing - The Company requested, and received, BPU approval of its MGP expenditures incurred through June 2011, which continued its existing overall SBC rate and recovery that was approved by the BPU, effective November 2011.

Additionally, in November 2012, the BPU approved the Company's funding obligations for NJCEP for the period from January 2013 to June 2013 of approximately $9.8 million. In June 2013, the BPU approved the Company's funding obligations for July 2013 to June 2014, of approximately $15.6 million. Accordingly, the Company recorded the obligation and corresponding regulatory asset on the Consolidated Balance Sheets.

- June 2012 USF filing - The Company filed to reduce the USF recovery rate resulting in a .1 percent decrease for the average residential heating customer. The rate was approved by the BPU effective October 2012.

- June 2013 USF filing - The Company filed to reduce the USF recovery rate resulting in a .5 percent decrease for the average residential heating customer. The rate was approved by the BPU in October 2013.

- July 2013 SBC filing - The Company requested approval of its MGP expenditures incurred through June 2013, as well as a reduction in the RA factor to $18.7 million annually and to increase its NJCEP factor for a net increase of 1.7 percent to the average residential heat customer. The petition was provisionally approved by the BPU on November 22, 2013.

Other Regulatory Initiatives

In June 2012, the BPU approved a pilot program for the Company to invest up to $10 million to construct NGV refueling stations in Monmouth, Ocean and Morris counties. The Company intends to begin construction of the stations by December 2013, and include a cost recovery filing to the BPU within the Company's next base rate case no later than November 15, 2015. The NGV program is authorized to earn an overall weighted average cost of capital of 7.1 percent, including a cost of equity of 10.3 percent. A portion of the proceeds from the utilization of the NGV equipment, along with any available federal and state incentives, will be credited against the cost of this investment. As of September 30, 2013, the Company has begun development on three NGV stations for a total investment of approximately 7.5 million.

In November 2012, the Company filed a petition with the BPU requesting deferred accounting for uninsured incremental O&M costs associated with Superstorm Sandy, which was subsequently approved in May 2013. In addition, the Company requested that the review of and the appropriate recovery period for such deferred expenses be addressed in the Company's next base rate case. As of September 30, 2013, the Company has deferred $14.8 million of these costs as a regulatory asset.

In December 2012, the Company filed a petition with the BPU requesting approval of a municipal consent in the Borough of Sayreville, New Jersey to provide natural gas distribution service to Red Oak Power, LLC, an electric generating facility. In January 2013, the Company filed a petition with the BPU requesting approval of a gas service agreement between TAQA GEN-X, LLC and the Company in order to provide supply to Red Oak Power, LLC. The municipal consent was approved by the BPU in September 2013. The service agreement portion of the request remains under BPU review.

In March 2013, the BPU issued an Order establishing a generic proceeding to review the prudency of costs incurred by New Jersey utility companies in response to major storm events in 2011 and 2012. In July 2013, the Company filed its detailed report including unreimbursed, uninsured incremental storm restoration costs and capital expenditures related to Superstorm Sandy.

In September 2013, the Company filed a petition seeking approval of its NJ RISE program. The submission was made in response to the BPU's order of March 2013, initiating a proceeding to investigate prudent, cost efficient and effective opportunities to protect New Jersey's utility infrastructure from future major storm events. The program includes six capital investment projects totaling $102.5 million over a five-year period, excluding AFUDC, for gas distribution storm hardening and mitigation projects, along with incremental O&M expenses.

4. DERIVATIVE INSTRUMENTS

The Company is subject to commodity price risk due to fluctuations in the market price of natural gas. To manage this risk, the Company enters into a variety of derivative instruments including, but not limited to, futures contracts, physical forward contracts, financial options and swaps to economically hedge the commodity price risk associated with its existing and anticipated commitments to purchase and sell natural gas. Accordingly, all of the financial derivative instruments are recorded at fair value on the Balance Sheets. For a more detailed discussion of the Company's fair value measurement policies and level disclosures associated with derivative instruments, see *Note 5. Fair Value*.

Changes in fair value of the Company's derivative instruments, however, are recorded as a component of regulatory assets or liabilities on the Balance Sheets, as the Company has received regulatory approval to defer and to recover these amounts through future BGSS rates as an increase or decrease to the cost of natural gas in the Company's tariff.

The Company elects normal purchase/normal sale accounting treatment on all physical commodity contracts. These contracts are accounted for on an accrual basis. Accordingly, gains or (losses) are recognized in earnings when the contract settles and the natural gas is delivered.

Fair Value of Derivatives

The following table reflects the fair value of the Company's derivative assets and liabilities recognized on the Balance Sheets as of September 30:

		Fair Value			
		2013		2012	
(Thousands)	Balance Sheet Location	**Asset Derivatives**	**Liability Derivatives**	Asset Derivatives	Liability Derivatives
Financial commodity contracts	Derivatives - current	**$ 3,502**	**$ 2,045**	$ 6,203	$ 5,034
	Derivatives - noncurrent	**121**	**140**	1,000	—
Total fair value of derivatives		**$ 3,623**	**$ 2,185**	$ 7,203	$ 5,034

Losses associated with the Company's financial derivatives totaled $1.8 million and $25.3 million for the fiscal years ended September 30, 2013 and 2012, respectively. These derivatives are part of its risk management activities that relate to its natural gas purchasing activities and BGSS incentive programs. As these transactions are entered into pursuant to and recoverable through regulatory riders, any changes in the value of the Company's financial derivatives are deferred in regulatory assets or liabilities and there is no impact to earnings.

As of September 30, 2013, the Company had the following outstanding long derivatives:

	Volume (Bcf)	
	2013	2012
Futures	**22.6**	16.1
Swaps (1)	—	3.4

(1) In October 2012, following the implementation of the Dodd-Frank Act, the ICE converted its cleared energy "swap" contracts to "futures" contracts and the NYMEX amended their product titles to remove the word "swap" from the titles of their "futures" and "option" contracts.

Broker Margin

Generally, exchange-traded futures contracts require posted collateral, referred to as margin, usually in the form of cash. The amount of margin required is comprised of a fixed initial amount based on the contract and a variable amount based on market price movements from the initial trade price. The Company's broker margin account balances as of September 30, are as follows:

(Thousands)	Balance Sheet Location	**2013**	2012
Broker margin deposit	Broker margin - Current assets	**$ 213**	$ 1,713

Wholesale Credit Risk

The Company is exposed to credit risk as a result of their wholesale marketing activities. As a result of the inherent volatility in the prices of natural gas commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If a counterparty failed to perform the obligations under its contract (e.g., failed to deliver or pay for natural gas), then the Company could sustain a loss.

The Company monitors and manages the credit risk of its wholesale marketing operations through credit policies and procedures that management believes reduce overall credit risk. These policies include a review and evaluation of current and prospective counterparties' financial statements and/or credit ratings, daily monitoring of counterparties' credit limits and exposure, daily communication with traders regarding credit status and the use of credit mitigation measures, such as collateral requirements and netting agreements. Examples of collateral include letters of credit and cash received for either prepayment or margin deposit. Collateral may be requested due to the Company's election not to extend credit or because exposure exceeds defined thresholds. Most of the Company's wholesale marketing contracts contain standard netting provisions. These contracts include those governed by the International Swaps and Derivatives Association (ISDA) and the North American Energy Standards Board (NAESB). The netting provisions refer to payment netting, whereby receivables and payables with the same counterparty are offset and the resulting net amount is paid to the party to which it is due.

Internally-rated exposure applies to counterparties that are not rated by Standard & Poor's (S&P) or Moody's Investors Service, Inc. (Moody's). In these cases, the company's or guarantor's financial statements are reviewed, and similar methodologies and ratios used by S&P and/or Moody's are applied to arrive at a substitute rating. Gross credit exposure is defined as the unrealized fair value of physical and financial derivative commodity contracts plus any outstanding wholesale receivable for the value of natural gas delivered and/or financial derivative commodity contract that has settled for which payment has not yet been received. The amounts presented below have not been reduced by any collateral received or netting and exclude accounts receivable for retail natural gas sales and services.

The following is a summary of gross credit exposures grouped by investment and noninvestment grade counterparties, as of September 30, 2013.

(Thousands)	**Gross Credit Exposure**
Investment grade	**$ 10,917**
Noninvestment grade	**—**
Internally rated investment grade	**258**
Internally rated noninvestment grade	**74**
Total	**$ 11,249**

Conversely, certain of the Company's derivative instruments are linked to agreements containing provisions that would require cash collateral payments from the Company if certain events occur. These provisions vary based upon the terms in individual counterparty agreements and can result in cash payments if the Company's credit rating were to fall below its current level. The Company's credit rating, with respect to S&P, reflects the overall corporate credit profile. Specifically, most, but not all, of these additional payments will be triggered if the Company's debt is downgraded by the major credit agencies, regardless of investment grade status. As well, some of these agreements include threshold amounts that would result in additional collateral payments if the values of derivative liabilities were to exceed the maximum values provided for in relevant counterparty agreements. Other provisions include payment features that are not specifically linked to ratings, but are based on certain financial metrics.

Collateral amounts associated with any of these conditions, are determined based on a sliding scale and are contingent upon the degree to which the Company's credit rating and/or financial metrics deteriorate, and the extent to which liability amounts exceed applicable threshold limits. There was no aggregate fair value of derivative instruments with credit-risk-related contingent features that were in a liability position on September 30, 2013 and 2012. If all the thresholds related to the credit-risk-related contingent features underlying these agreements had been invoked on September 30, 2013 and 2012, the Company would not have been required to post any additional collateral to its counterparties. These amounts differ from the respective net derivative liabilities reflected on the Balance Sheets because the agreements also include clauses, commonly known as "Rights of Offset," that would permit the Company to offset its derivative assets against its derivative liabilities for determining additional collateral to be posted.

5. FAIR VALUE

Fair Value of Assets and Liabilities

The fair value of cash and cash equivalents, commercial paper and borrowings under revolving credit facilities are estimated to equal their carrying amounts due to the short maturity of those instruments. The estimated fair value of long-term debt, including current maturities and excluding capital leases, as applicable as of September 30, are as follows:

(Thousands)	**2013**	2012
Carrying value	**$ 379,845**	$ 329,845
Fair market value	**$ 397,175**	$ 364,394

The Company utilizes a discounted cash flow method to determine the fair value of its debt. Inputs include observable municipal and corporate yields, as appropriate, for the maturity of the specific issue and

NJR's credit rating. As of September 30, 2013 and 2012, the Company discloses its debt within Level 2 of the fair value hierarchy.

Fair Value Hierarchy

The Company applies fair value measurement guidance to its financial assets and liabilities, as appropriate, which include financial derivatives. In addition, authoritative accounting literature prescribes the use of a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value based on the source of the data used to develop the price inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to inputs that are based on unobservable market data and include the following:

Level 1 Unadjusted quoted prices for identical assets or liabilities in active markets. the Company's Level 1 assets and liabilities include exchange traded futures contracts, listed equities, and money market funds. Exchange traded futures contracts include all energy contracts traded on the New York Mercantile (NYMEX)/Chicago Mercantile Exchange (CME) and Intercontinental Exchange (ICE) that the Company refers internally to as basis swaps, fixed swaps and futures that are cleared through a Futures Commission Merchant (FCM).

Level 2 Other significant observable inputs such as interest rates or price data, including both commodity and basis pricing that is observed either directly or indirectly from publications or pricing services. Level 2 financial derivatives consist of transactions with non-FCM counterparties (basis swaps, fixed swaps and/or options).

Level 3 Inputs derived from a significant amount of unobservable market data; these include the Company's best estimate of fair value and are derived primarily through the use of internal valuation methodologies.

The Company's financial derivatives portfolios consist mainly of futures and swaps. The Company primarily uses the market approach and its policy is to use actively quoted market prices when available. The principal market for its derivative transactions is the natural gas wholesale market, therefore, the primary source for its price inputs is the NYMEX exchange.

When the Company determines fair values, measurements are adjusted, as needed, for credit risk associated with its counterparties, as well as its own credit risk. The Company determines these adjustments by using historical default probabilities that correspond to the applicable S&P issuer ratings, while also taking into consideration collateral and netting arrangements that serve to mitigate risk.

Assets and liabilities measured at fair value on a recurring basis are summarized as follows:

(Thousands)	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
As of September 30, 2013:				
Assets:				
Financial derivative contracts - natural gas	$ 3,623	$ —	$ —	$ 3,623
Total assets at fair value	**$ 3,623**	**$ —**	$ —	**$ 3,623**
Liabilities:				
Financial derivative contracts - natural gas	$ 2,185	$ —	$ —	$ 2,185
Total liabilities at fair value	**$ 2,185**	**$ —**	**$ —**	**$ 2,185**
As of September 30, 2012:				
Assets:				
Financial derivative contracts - natural gas	$ 7,201	$ 2	$ —	$ 7,203
Total assets at fair value	$ 7,201	$ 2	$ —	$ 7,203
Liabilities:				
Financial derivative contracts - natural gas	$ 5,031	$ 3	$ —	$ 5,034
Total liabilities at fair value	$ 5,031	$ 3	$ —	$ 5,034

6. DEBT

The following table presents the long-term debt of the Company as of September 30:

(Thousands)			**2013**	2012
Long-Term Debt				
First mortgage bonds:		Maturity date:		
5.00%	Series HH	December 1, 2038	**12,000**	12,000
4.50%	Series II	August 1, 2023	**10,300**	10,300
4.60%	Series JJ	August 1, 2024	**10,500**	10,500
4.90%	Series KK	October 1, 2040	**15,000**	15,000
5.60%	Series LL	May 15, 2018	**125,000**	125,000
Variable	Series MM	September 1, 2027	**9,545**	9,545
Variable	Series NN	August 1, 2035	**41,000**	41,000
Variable	Series OO	August 1, 2041	**46,500**	46,500
3.15%	Series PP	April 15, 2028	**50,000**	—
4.77% Unsecured senior notes		March 15, 2014	**60,000**	60,000
Capital lease obligation-Buildings		June 1, 2021	**20,381**	21,907
Capital lease obligation-Meters		Various dates	**31,261**	30,887
Capital lease obligation-Equipment		December 1, 2013	**42**	290
Less: Current maturities of long-term debt			**(68,643)**	(7,760)
Total long-term debt			**$ 362,886**	$ 375,169

Annual long-term debt redemption requirements, excluding capital leases, as of September 30, are as follows (in millions):

September 30,	Redemption
2014	$ 60.0
2015	$ —
2016	$ —
2017	$ —
2018	$ 125.0
Thereafter	$ 194.8

First Mortgage Bonds

The Company's mortgage secures its First Mortgage Bonds and represents a lien on substantially all of its property, including natural gas supply contracts. Certain indentures supplemental to the mortgage include restrictions as to cash dividends and other distributions on the Company's common stock that apply as long as certain series of First Mortgage Bonds are outstanding. As of September 30, 2013, under the most restrictive provision, $339.8 million of the Company's retained earnings was available for dividends.

The Company has three series of Variable Rate Demand Notes (VRDN) with a total principal amount of $97 million with maturity dates ranging from September 2027 to August 2041. VRDNs are sold to investors on a daily basis with the interest rate set by the remarketing agent. In the case where the remarketing agent is unable to sell the VRDNs to an investor on a given day, the Company would be required to repurchase the EDA Bonds. Therefore, in conjunction with the issuance of the EDA Bonds, the Company entered into a credit facility with JPMorgan Chase Bank, N.A. as described below in the *Short-term Debt* section, to provide liquidity support in the event of a failed remarketing of the EDA Bonds and to ensure payment of principal and interest. There would be no increase in the Company's debt if this were to occur.

The rates on these types of investments are generally correlated with the Securities Industry and Financial Markets Association Municipal Swap Index and will initially accrue interest at a daily rate, with a maximum rate of 12 percent per annum. As of September 30, 2013, the interest rate on these securities was .09 percent.

On April 15, 2013, the Company issued $50 million of 3.15 percent senior secured notes due April 15, 2028, in the private placement market pursuant to a note purchase agreement entered into on February 8, 2013. Interest is payable semi-annually. The proceeds were used to refinance short-term debt and will fund capital expenditure requirements.

Sale-Leasebacks

The Company's master lease agreement for its headquarters building has a twenty-five and a half-year term that expires in June 2021, with two five-year renewal options. The present value of the agreement's minimum lease payments is reflected as both a capital lease asset and a capital lease obligation, which are included in utility plant and long-term debt, respectively, on the Balance Sheets.

The Company received $7.1 million and $6.5 million for fiscal 2013 and 2012, respectively, in connection with the sale-leaseback of its natural gas meters. During fiscal 2013 and 2012, the Company exercised early purchase options with respect to meter leases by making final principal payments of $752,000 and 1 million, respectively. This sale-leaseback program is expected to continue on an annual basis.

Contractual commitments for capital lease payments, as of the fiscal years ended September 30, are as follows (in millions):

(Millions)	Lease Payment
2014	$11.3
2015	10.7
2016	10.9
2017	9.8
2018	7.9
Thereafter	11.3
Subtotal	61.9
Less: interest component	(10.2)
Total	**$51.7**

Short-term Debt

A summary of the Company's credit facilities, which require commitment fees on the unused amounts, as of September 30, are as follows:

(Thousands)	**2013**	2012
Bank credit facility dedicated to EDA Bonds *(1) (2)*	**$ 100,000**	$ 100,000
Bank revolving credit facilities *(1)*	**$ 250,000**	$ 200,000
Amount outstanding at end of period	**$ 168,600**	$ 135,000
Weighted average interest rate at end of period	**0.13%**	0.18%
Amount available at end of period *(3)*	**$ 81,400**	$ 65,000

(1) Committed credit facilities, which require commitment fees on the unused amounts.
(2) There were no borrowings outstanding as of September 30, 2013 and 2012, respectively.
(3) Letters of credit outstanding total $266,000 as of September 30, 2013, which reduces amount available. There were no letters of credit outstanding as of September 30, 2012.

The Company has a $100 million, four-year credit facility with JPMorgan Chase Bank, N.A. that expires in August 2015, to provide liquidity support in the event of a failed remarketing of the EDA Bonds and to ensure payment of principal and interest.

The Company has a $250 million unsecured committed credit facility expiring August 2014, which permits an increase to the facility, from time to time, with the existing or new lenders, in a minimum of $15 million increments up to a maximum of $50 million at the lending banks' discretion. The credit facility is used to support the Company's commercial paper program and provides for the issuance of letters of credit. As of September 30, 2013, the Company had $168.6 million in borrowings outstanding under the facility.

As of September 30, 2013, the Company has one letter of credit outstanding for $266,000. The Company's letter of credit is used for collateral for a remediation project and expires on August 2014. This letter of credit reduces the amount available under the Company's committed credit facility by the same amount. The Company does not anticipate that this letter of credit will be drawn upon by the counterparty, and it will be renewed as necessary.

7. EMPLOYEE BENEFIT PLANS

Pension and Other Postemployment Benefit Plans (OPEB)

The Company has two trusteed, noncontributory defined benefit retirement plans covering regular represented and nonrepresented employees with more than one year of service. All non-represented employees hired on or after October 1, 2009, and represented employees hired on or after January 1, 2012, are covered by an enhanced defined contribution plan instead of the defined benefit plan.

Defined benefit plan benefits are based on years of service and average compensation during the highest sixty consecutive months of employment.

The Company also maintains an unfunded nonqualified pension equalization plan (PEP) that was established to provide employees with the full level of benefits as stated in the qualified plan without reductions due to various limitations imposed by the provisions of federal income tax laws and regulations. There were no plan assets in the nonqualified plan due to the nature of the plan.

The Company provided postemployment medical and life insurance benefits to employees who meet certain eligibility requirements. During fiscal 2012, the Plan was amended so that represented employees hired on or after January 1, 2012, are no longer eligible for postemployment medical benefits.

The Company's funding policy for its pension plans is to contribute at least the minimum amount required by the Employee Retirement Income Security Act of 1974, as amended. In fiscal 2013 and 2012, the Company had no minimum funding requirements; however, the Company made discretionary contributions to the pension plans totaling $20 million during both fiscal 2013 and 2012. The Company elected to make these discretionary tax-deductible contributions to improve the funded status of the pension plans. The Company does not expect to be required to make additional contributions to fund the pension plans over the next three fiscal years based on current actuarial assumptions; however, funding requirements are uncertain and can depend significantly on changes in actuarial assumptions, returns on plan assets and changes in the demographics of eligible employees and covered dependents. In addition, as in the past, the Company may elect to make contributions in excess of the minimum required amount to the plans.

There are no Federal requirements to pre-fund OPEB benefits. However, the Company is required to fund certain amounts due to regulatory agreements with the BPU. The Company contributed $6 million and $5.8 million, respectively, in fiscal 2013 and 2012 and estimates that it will contribute between $3 million to $5 million over the next five years. Additional contributions may be required based on market conditions and changes to assumptions.

The following summarizes the changes in the funded status of the plans and the related liabilities recognized on the Balance Sheets as of September 30:

	Pension [1]		OPEB	
(Thousands)	**2013**	2012	**2013**	2012
Change in Benefit Obligation				
Benefit obligation at beginning of year	**$ 154,265**	$ 125,636	**$ 101,794**	$ 80,030
Service cost	**4,564**	3,559	**3,184**	2,483
Interest cost	**6,521**	6,465	**4,322**	4,137
Plan participants' contributions	**41**	39	**32**	29
Amendments	**—**	1,083	**—**	(2,922)
Actuarial (gain) loss	**(14,515)**	22,233	**(12,077)**	20,206
Benefits paid, net of retiree subsidies received	**(4,826)**	(4,750)	**(2,478)**	(2,169)
Benefit obligation at end of year	**$ 146,050**	$ 154,265	**$ 94,777**	$ 101,794
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 123,875**	$ 87,836	**$ 40,485**	$ 30,916
Actual return on plan assets	**14,784**	20,705	**5,047**	6,128
Employer contributions	**20,049**	20,045	**5,977**	5,775
Benefits paid, net of plan participants' contributions	**(4,785)**	(4,711)	**(2,632)**	(2,334)
Fair value of plan assets at end of year	**$ 153,923**	$ 123,875	**$ 48,877**	$ 40,485
Funded status	**$ 7,873**	$ (30,390)	**$ (45,900)**	$ (61,309)
Amounts recognized on the Balance Sheets				
Postemployment employee benefit (liability) asset				
Current	**$ (47)**	$ (48)	**$ (100)**	$ (121)
Non-current	**7,920**	(30,342)	**(45,800)**	(61,188)
Total	**$ 7,873**	$ (30,390)	**$ (45,900)**	$ (61,309)

(1) Includes the Company's PEP.

The Company recognizes a liability for its underfunded benefit plans as required by the *Compensation - Retirement Benefits* Topic of the ASC 715 and records the offset to regulatory assets.

The following table summarizes the amounts recognized in regulatory assets as of September 30:

	Pension	OPEB
Balance at September 30, 2011	$ 72,355	$ 47,925
Amounts arising during the period:		
Net actuarial loss	10,896	16,773
Amounts amortized to net periodic costs:		
Net actuarial (loss)	(3,848)	(2,671)
Prior service cost	1,046	(2,677)
Net transition obligation	—	(551)
Balance at September 30, 2012 [1]	$ 80,449	$ 58,799
Amounts arising during the period:		
Net actuarial (gain)	**(17,961)**	**(13,523)**
Amounts amortized to net periodic costs:		
Net actuarial (loss)	**(5,719)**	**(3,743)**
Prior service cost	**(105)**	**301**
Net transition obligation	**—**	**(22)**
Balance at September 30, 2013	**$ 56,664**	**$ 41,812**

(1) Balance represents amounts recognized in accordance with ASC 715 and excludes $308,000 associated with a regulatory asset approved by the BPU for fiscal 2012.

The amounts in regulatory assets and accumulated other comprehensive income not yet recognized as components of net periodic benefit cost as of September 30 are:

	Pension		OPEB	
(Thousands)	**2013**	2012	**2013**	2012
Net actuarial loss	**$ 55,559**	$ 79,239	**$ 44,140**	$ 61,406
Prior service cost (credit)	**1,105**	1,210	**(2,339)**	(2,640)
Net transition obligation	**—**	—	**11**	33
Total	**$ 56,664**	$ 80,449	**$ 41,812**	$ 58,799

Amounts included in regulatory assets expected to be recognized as components of net periodic benefit cost in fiscal 2014 are as follows:

(Thousands)	Pension	OPEB
Net actuarial gain	**$ 4,348**	**$ 2,607**
Prior service credit	**108**	**11**
Net transition obligation	**—**	**(303)**
Total	**$ 4,456**	**$ 2,315**

The accumulated benefit obligation (ABO) for the pension plans, including the Pension Equalization Plan exceeded the fair value of plan assets. The projected benefit and accumulated benefit obligations and the fair value of plan assets as of September 30, are as follows:

	Pension	
(Thousands)	**2013**	2012
Projected benefit obligation	**$ 146,050**	$ 154,265
Accumulated benefit obligation	**$ 130,422**	$ 137,613
Fair value of plan assets	**$ 153,923**	$ 123,875

The components of the net periodic cost for pension benefits, including the Company's Pension Equalization Plan, and OPEB costs (principally health care and life insurance) for employees and covered dependents for fiscal years ended September 30, are as follows:

	Pension		OPEB	
(Thousands)	**2013**	2012	**2013**	2012
Service cost	**$ 4,564**	$ 3,559	**$ 3,184**	$ 2,483
Interest cost	**6,521**	6,465	**4,322**	4,137
Expected return on plan assets	**(11,338)**	(9,368)	**(3,601)**	(2,695)
Recognized actuarial loss	**5,719**	3,848	**3,743**	2,671
Prior service cost amortization	**105**	36	**(301)**	19
Recognized net initial obligation	**—**	—	**22**	286
Net periodic benefit cost	**$ 5,571**	$ 4,540	**$ 7,369**	$ 6,901

The weighted average assumptions used to determine benefit costs during the fiscal year and obligations as of September 30, are as follows:

	Pension		OPEB	
	2013	2012	**2013**	2012
Benefit costs:				
Discount rate	**4.30%**	5.25%	**4.30%**	5.25%
Expected asset return	**8.50%**	8.25%	**8.50%**	8.25%
Compensation increase	**3.25%**	3.25%	**3.25%**	3.25%
Obligations:				
Discount rate	**5.15%**	4.30%	**5.15%**	4.30%
Compensation increase	**3.25%**	3.25%	**3.25%**	3.25%

In selecting an assumed discount rate, the Company uses a modeling process that involves selecting a portfolio of high-quality corporate debt issuances (AA- or better) whose cash flows (via coupons or maturities) match the timing and amount of the Company's expected future benefit payments. The Company considers the results of this modeling process, as well as overall rates of return on high-quality corporate bonds and changes in such rates over time, to determine its assumed discount rate.

Information relating to the assumed health care cost trend rate (HCCTR) used to determine expected OPEB benefits as of September 30, and the effect of a one percent change in the rate, are as follows:

($ in thousands)	**2013**	2012
HCCTR	**7.3%**	7.5%
Ultimate HCCTR	**4.8%**	4.8%
Year ultimate HCCTR reached	**2022**	2022
Effect of a 1 percentage point increase in the HCCTR on:		
Year-end benefit obligation	**$ 15,170**	$ 17,931
Total service and interest cost	**$ 1,624**	$ 1,409
Effect of a 1 percentage point decrease in the HCCTR on:		
Year-end benefit obligation	**$ (12,318)**	$ (14,348)
Total service and interest costs	**$ (1,263)**	$ (1,099)

The Company's investment objective is a long-term real rate of return on assets before permissible expenses that is approximately 5 percent greater than the assumed rate of inflation as measured by the consumer price index. The expected long-term rate of return is based on the asset categories in which the Company invests and the current expectations and historical performance for these categories.

The mix and targeted allocation of the pension and OPEB plans' assets are as follows:

Asset Allocation	**2014 Target Allocation**	**Assets at September 30, 2013**	2012
U.S. equity securities	40%	**42%**	39%
International equity securities	20	**22**	21
Fixed income	40	**36**	40
Total	100%	**100%**	100%

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid during the following fiscal years:

(Thousands)	**Pension**	**OPEB**
2014	$ 5,537	$ 3,058
2015	$ 5,917	$ 3,545
2016	$ 6,340	$ 4,006
2017	$ 6,657	$ 4,465
2018	$ 7,173	$ 4,908
2019 - 2023	$ 43,466	$ 31,524

The Company 's OPEB plans provide prescription drug benefits that are actuarially equivalent to those provided by Medicare Part D. Therefore, under the Medicare Prescription Drug, Improvement and Modernization Act of 2003 the Company qualifies for federal subsidies.

The estimated subsidy payments are:

Fiscal Year	**Estimated Subsidy Payment** *(Thousands)*
2014	$ 207
2015	$ 222
2016	$ 241
2017	$ 261
2018	$ 282
2019 - 2023	$ 1,821

Pension and OPEB assets held in the master trust, measured at fair value are summarized as follows:

	Quoted Prices in Active Markets for Identical Assets (Level 1)			
(Thousands)	**Pension**		**OPEB**	
Assets	**2013**	2012	**2013**	2012
Money market funds	**$ 2**	$ —	**$ 1,134**	$ 1,142
Registered Investment Companies-				
Equity Funds				
Large Cap Index Fund	**53,584**	40,884	**16,195**	13,022
Vanguard Extended Market Index Fund	**11,328**	7,424	**3,397**	2,345
Vanguard Total International Stock	**32,895**	25,469	**9,896**	8,046
Fixed Income Funds				
Emerging Markets Debt Fund	**6,729**	6,229	**11,524**	10,057
High Yield Bond Fund	**15,259**	12,364	**2,133**	1,968
Long Duration Fund	**34,126**	31,505	**4,598**	3,905
Total assets at fair value	**$ 153,923**	$ 123,875	**$ 48,877**	$ 40,485

The plan had no Level 2 or Level 3 fair value measurements during the two fiscal years and there have been no changes in valuation methodologies as of September 30, 2013. The following is a description of the valuation methodologies used for assets measured at fair value:

Money Market funds: Represents bank balances and money market funds which are valued based on the net asset value of shares held at year end.

Registered Investment Companies: Equity and fixed income funds valued at the net asset value (NAV) of shares held by the plan at year end as reported on the active market on which the individual securities are traded.

The methods previously described may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Company believes its valuation methods 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.

Defined Contribution Plan

The Company offers an Employees' Retirement Savings Plan (Savings Plan) to eligible employees. The Company matches 55 percent of participants' contributions up to 6 percent of base compensation. The Company's non-represented employees hired on or after October 1, 2009, and represented employees hired on or after January 1, 2012, are eligible for an employer special contribution of between 2 percent and 3 percent of base compensation, depending on years of service, into the Savings Plan on their behalf. The amount expensed and contributed for the matching provision of the Savings Plan was $1.2 million in fiscal 2013 and $1 million in fiscal 2012. The amount contributed for the employer special contribution of the Savings Plan was $20,000 and $8,100 in fiscal 2013 and 2012, respectively.

8. ASSET RETIREMENT OBLIGATIONS (ARO)

The Company recognizes AROs related to the costs associated with cutting and capping its main and service gas distribution pipelines, which are required by New Jersey law when taking such gas distribution pipeline out of service.

The following is an analysis of the change in the ARO liability for the fiscal years ended September 30:

(Thousands)	**2013**	2012
Balance at October 1	**$ 27,983**	$ 27,026
Accretion	**1,892**	1,774
Additions	**533**	380
Retirements	**(1,697)**	(1,197)
Balance at period end	**$ 28,711**	$ 27,983

Accretion amounts are deferred as a regulatory asset and netted against regulatory liabilities, for presentation purposes, on the Balance Sheets.

Accretion for the next five years is estimated to be as follows:

(Thousands) **Fiscal Years Ended September 30,**	**Estimated Accretion**
2014	$ 1,975
2015	2,037
2016	2,099
2017	2,152
2018	2,204
Total	$ 10,467

9. INCOME TAXES

A reconciliation of the United States federal statutory rate of 35 percent to the effective rate from operations for the fiscal years ended September 30, 2013 and 2012 are as follows:

(Thousands)	**2013**	2012
Statutory income tax expense	**$ 38,236**	$ 38,980
Change resulting from:		
State income taxes	**4,122**	4,107
Depreciation and cost of removal	**(5,769)**	(3,999)
Investment tax credits (ITC)	**(322)**	(322)
Other	**(868)**	(631)
Income tax provision	**$ 35,399**	$ 38,135
Effective income tax rate	**32.4%**	34.2%

The income tax provision (benefit) from operations consists of the following:

(Thousands)	**2013**	2012
Current		
Federal	**$ 3,479**	$ 13,186
State	**1,416**	2,268
Deferred		
Federal	**25,899**	18,936
State	**4,927**	4,067
Investment tax credits	**(322)**	(322)
Income tax provision	**$ 35,399**	$ 38,135

The temporary differences, which give rise to deferred tax assets and (liabilities), consist of the following:

(Thousands)	**2013**	2012
Deferred tax assets		
Investment tax credits	**$ 3,012**	$ 3,182
Incentive compensation	**1,365**	1,898
Other	**5,964**	5,802
Total deferred tax assets	**$ 10,341**	$ 10,882
Deferred tax liabilities		
Property related items	**$ (286,220)**	$ (259,587)
Remediation costs	**(18,881)**	(24,018)
Post employment benefits	**(26,507)**	(21,298)
Conservation incentive plan	**(7,611)**	(11,200)
Under-recovered gas costs	**(383)**	(2,835)
Other	**(12,361)**	(3,428)
Total deferred tax liabilities	**$ (351,963)**	$ (322,366)
Total net deferred tax liabilities	**$ (341,622)**	$ (311,484)

The Company's federal income tax returns through fiscal 2009 have either been reviewed by the IRS, or the related statute of limitations has expired and all matters have been settled. The IRS is currently examining fiscal 2010 tax return.

The State of New Jersey has completed its sales and use tax examinations through March 31, 2010, and its corporate business tax examinations through September 30, 2009. All periods subsequent to those ended September 30, 2009, are statutorily open to examination.

The Company evaluates its tax positions to determine the appropriate accounting and recognition of potential future obligations associated with unrecognized tax benefits. As of September 30, 2013 and 2012, based on its analysis, the Company determined that there was no need to recognize any liabilities associated with uncertain tax positions.

In September 2013, the U.S. Department of the Treasury and the IRS released final regulations that provide guidance on applying Section 263(a) of the Internal Revenue Code to amounts paid to acquire, produce, or improve tangible property, as well as rules for materials and supplies. Implementation of these final regulations in September 2013 had no material impact on the Company's results of operations, financial condition or cash flow.

10. COMMITMENTS AND CONTINGENT LIABILITIES

Cash Commitments

The Company has entered into long-term contracts, expiring at various dates through August 2030, for the supply, storage and delivery of natural gas. These contracts include current annual fixed charges of approximately $96 million at current contract rates and volumes, which are recoverable through BGSS.

Commitments as of September 30, 2013, for natural gas purchases and future demand fees for the next five fiscal year periods are as follows:

(Thousands)	2014	2015	2016	2017	2018	Thereafter
Natural gas purchases	$ 104,466	$ 100,487	$ 8,564	$ 113	$ —	$ —
Storage demand fees	29,082	22,158	12,396	9,993	9,299	13,948
Pipeline demand fees	66,796	41,326	35,762	33,440	33,171	193,593
Total [(1)]	**$ 200,344**	**$ 163,971**	**$ 56,722**	**$ 43,546**	**$ 42,470**	**$ 207,541**

(1) Does not include amounts related to intercompany asset management agreements with NJRES.

As of September 30, 2013, the Company's future minimum lease payments under various operating leases will not be more than $890,000 annually for the next five years and $190,000 in the aggregate for all years thereafter.

Guarantees

The Company enters into agreements to lease vehicles, generally over a five-year term, that qualify as operating leases. These agreements contain provisions that could require the Company to make additional cash payments at the end of the term for a portion of the residual value of the vehicles. As of September 30, 2013, the present value of the liability recognized on the Balance Sheets is $554,000. In the event performance under the guarantee is required, the Company's maximum future payment would be $755,000.

Legal Proceedings

Manufactured Gas Plant Remediation

The Company is responsible for the remedial cleanup of five MGP sites, dating back to gas operations in the late 1800s and early 1900s that contain contaminated residues from former gas manufacturing operations. The Company is currently involved in administrative proceedings with the New Jersey Department of Environmental Protection (NJDEP), as well as participating in various studies and investigations by outside consultants to determine the nature and extent of any such contaminated residues and to develop appropriate programs of remedial action, where warranted, under Administrative Consent Orders or Memoranda of Agreement with the NJDEP.

The Company may, subject to BPU approval, recover its remediation expenditures, including carrying costs, over rolling seven-year periods pursuant to a RA approved by the BPU. In February 2012, the Company, filed its 2011 SBC filing, requesting approval of its MGP expenditures incurred through June 30, 2011, which would continue its existing overall SBC rate and recovery at approximately $20 million. In July 2013, the Company requested approval of its MGP expenditures incurred through June 2013 as well as a reduction in the RA factor to $18.7 million annually. The petition was provisionally approved by the BPU on November 22, 2013. As of September 30, 2013, $47 million of previously incurred remediation costs, net of recoveries from customers and insurance proceeds, are included in regulatory assets on the Balance Sheets.

The Company periodically, and at least annually, performs an environmental review of the MGP sites, including a review of potential liability for investigation and remedial action. The Company estimated at the time of the review that total future expenditures to remediate and monitor the five MGP sites for which it is responsible, including potential liabilities for Natural Resource Damages that might be brought by the NJDEP for alleged injury to groundwater or other natural resources concerning these sites, will range from approximately $159.8 million to $261.2 million. The Company's estimate of these liabilities is based upon known facts, existing technology and enacted laws and regulations in place when the review was completed. Where it is probable that costs will be incurred, and the information is sufficient to establish a range of possible liability, the Company accrues the best estimated amount in the range. If no point within the range is more likely than the other, it is the Company's policy to accrue the lower end of the range. Accordingly, as of September 30, 2013, the Company recorded an MGP remediation liability and a corresponding regulatory asset of $183.6 million on the Balance Sheets, based on the best estimate. The actual costs to be incurred by the Company are dependent upon several factors, including final determination of remedial action, changing technologies and governmental regulations, the ultimate ability of other responsible parties to pay and any insurance recoveries.

The Company will continue to seek recovery of MGP-related costs through the RA. If any future regulatory position indicates that the recovery of such costs is not probable, the related non-recoverable costs would be charged to income in the period of such determination. However, because recovery of such costs is subject to BPU approval, there can be no assurance as to the ultimate recovery through the RA or the impact on the Company's results of operations, financial position or cash flows, which could be material.

General

The Company is party to various other claims, legal actions and complaints arising in the ordinary course of business. In the Company's opinion, the ultimate disposition of these matters will not have a material effect on its financial condition, results of operations or cash flows.

11. RELATED PARTY TRANSACTIONS

The Company participates in various transactions with NJR and other subsidiaries of NJR in the ordinary course of business. These transactions result in either charges or credits to operation and maintenance expense in the Statements of Operations.

The following table summarizes charges from NJR and NJR Service Corporation (NJRSC) during fiscal 2013 and 2012. Charges from NJR were for various services, including executive management and corporate governance. Charges from NJRSC were primarily related to financial and administrative, legal, human resources, corporate communications, taxation, internal audit and technology services.

(*Thousands*)	**2013**	2012
NJR	**$ 7,521**	$ 6,994
NJRSC	**19,902**	20,167
Total	**$ 27,423**	$ 27,161

The following table summarizes charges from the Company to NJR Home Services (NJRHS), NJR Energy Services (NJRES), NJR, NJR Clean Energy Ventures (NJRCEV) and Commercial Realty and Resources (CR&R) during fiscal 2013 and 2012. Charges to NJRHS were for services related to billing, customer inquiry, payment processing, vehicle fleet maintenance and operating expenses. Charges to NJRES were for administrative services and operating expenses. Charges to NJR were for operating expenses. Charges to NJRCEV were for services related to billing and payment processing and operating expenses. Charges to CR&R were for operating expenses.

(*Thousands*)	**2013**	2012
NJRHS	**$ 3,994**	$ 3,624
NJRES	**568**	556
NJR	**496**	427
NJRCEV	**425**	467
CR&R	**21**	24
Total	**$ 5,504**	$ 5,098

The following table reflects the receivable (payable) the Company had with NJR and other subsidiaries of NJR including NJR Steckman Ridge Storage Company (NJRSR) at September 30, 2013 and 2012, which are included in accounts payable and other on the Balance Sheets:

(*Thousands*)	**2013**	2012
NJR	**$ (1,589)**	$ (1,218)
NJRES	**16**	43
NJRHS	**(1,040)**	(432)
CR&R	**17**	18
NJRSC	**(1,200)**	(1,642)
NJRCEV	**68**	71
Total	**$ (3,728)**	$ (3,160)

The Company may periodically purchase natural gas from NJRES. During the fiscal years ended September 30, 2013 and 2012, the Company purchased natural gas from NJRES in the amount of $5 million and $2.5 million, respectively.

In January 2010, the Company entered into a 10-year agreement effective April 1, 2010, for 3 Bcf of firm storage capacity with Steckman Ridge. Under the terms of the agreement, the Company incurs demand fees, at market rates, of approximately $9.3 million annually. These fees are recoverable through the Company's BGSS mechanism and are included in regulatory assets. Additionally, the Company has transportation capacity with Iroquois Gas Transmission that expires by January 2019. Demand fees associated with both Steckman Ridge and Iroquois Gas Transmission were $9.2 million and $9 million during the fiscal years ended September 30, 2013 and 2012, respectively. As of September 30, 2013 and 2012, the Company had fees payable to Steckman Ridge in the amount of $775,000 for both fiscal years. The Company had demand fees payable to Iroquois Gas Transmission of $61,000 for both fiscal years.

In December 2009, the Company and NJRES entered into an asset management agreement that began in January 2010 and ends in March 2014. Under the terms of this agreement, the Company released certain transportation and storage contracts to NJRES for the entire term of the agreement. The Company also sold approximately 1 Bcf of natural gas in storage at cost to NJRES. In return, the Company has the option to purchase index priced gas from NJRES at the Company's citygate and other delivery locations to maintain operational reliability. In September 2010, the Company and NJRES entered into an another asset management agreement that began in September 2010 and ends October 2014, whereby the Company released additional transportation contracts to NJRES for the entire term of the agreement and has the option to purchase index priced gas from NJRES at the Company's citygate.