NATIONAL FUEL GAS CO
Form 10-Q
August 09, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2013

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from____ to_____

Commission File Number 1-3880

NATIONAL FUEL GAS COMPANY

(Exact name of registrant as specified in its charter)

New Jersey	13-1086010
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6363 Main Street	
Williamsville, New York	14221
(Address of principal executive offices)	(Zip Code)

(716) 857-7000

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. YES þ NO ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES þ NO ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer	þ	Accelerated Filer	¨
Non-Accelerated Filer	¨(Do not check if a smaller reporting company)	Smaller Reporting Company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ¨ NO þ

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Common stock, par value $1.00 per share, outstanding at July 31, 2013: 83,617,599 shares.

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GLOSSARY OF TERMS

Frequently used abbreviations, acronyms, or terms used in this report:

National Fuel Gas Companies

Company	The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire Pipeline, Inc.
ESNE	Energy Systems North East, LLC
Horizon Power	Horizon Power, Inc.
Midstream Corporation	National Fuel Gas Midstream Corporation
National Fuel	National Fuel Gas Company
NFR	National Fuel Resources, Inc.
Registrant	National Fuel Gas Company
Seneca	Seneca Resources Corporation
Supply Corporation	National Fuel Gas Supply Corporation

Regulatory Agencies

CFTC	Commodity Futures Trading Commission
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
NYDEC	New York State Department of Environmental Conservation
NYPSC	State of New York Public Service Commission
PaDEP	Pennsylvania Department of Environmental Protection
PaPUC	Pennsylvania Public Utility Commission
SEC	Securities and Exchange Commission

Other

2012 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2012
Bbl	Barrel (of oil)
Bcf	Billion cubic feet (of natural gas)
Bcfe (or Mcfe) – represents Bcf (or Mcf) Equivalent	The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. The Company uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.
Btu	British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit
Capital expenditure	Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.
Cashout revenues	A cash resolution of a gas imbalance whereby a customer pays Supply Corporation and/or Empire for gas the customer receives in excess of amounts delivered into Supply Corporation's and Empire's systems by the customer's shipper.
Degree day	A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.
Derivative	A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, options, no cost collars and swaps.

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Development costs	Costs incurred to obtain access to proved oil and gas reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act.
Dth	Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.
Exchange Act	Securities Exchange Act of 1934, as amended
Expenditures for long-lived assets	Includes capital expenditures, stock acquisitions and/or investments in partnerships.
Exploration costs	Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.
Firm transportation and/or storage	The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.
GAAP	Accounting principles generally accepted in the United States of America
Goodwill	An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.
Hedging	A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often times through the use of derivative financial instruments.
Hub	Location where pipelines intersect enabling the trading, transportation, storage, exchange, lending and borrowing of natural gas.
Interruptible transportation and/or storage	The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service, and for which the customer does not pay unless utilized.
LIBOR	London Interbank Offered Rate
LIFO	Last-in, first-out
Marcellus Shale	A Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York.
Mbbl	Thousand barrels (of oil)
Mcf	Thousand cubic feet (of natural gas)
MD&A	Management’s Discussion and Analysis of Financial Condition and Results of Operations
MDth	Thousand decatherms (of natural gas)
MMBtu	Million British thermal units (heating value of one decatherm of natural gas)
MMcf	Million cubic feet (of natural gas)
NGA	The Natural Gas Act of 1938, as amended; the federal law regulating interstate natural gas pipeline and storage companies, among other things, codified beginning at 15 U.S.C. Section 717.
NYMEX	New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Open Season	A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.
Precedent Agreement	An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called “conditions precedent”) happen, usually within a specified time.

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Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped (PUD) reserves	Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make these reserves productive.
Reserves	The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
Revenue decoupling mechanism	A rate mechanism which adjusts customer rates to render a utility financially indifferent to throughput decreases resulting from conservation.
S&P	Standard & Poor’s Rating Service
SAR	Stock appreciation right
Service agreement	

	The binding agreement by which the pipeline company agrees to provide service and the shipper agrees to pay for the service.
Stock acquisitions	Investments in corporations
VEBA	Voluntary Employees' Beneficiary Association
WNC	Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs

will be
recovered.

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•The Company has nothing to report under this item.

Reference to "the Company" in this report means the Registrant or the Registrant and its subsidiaries collectively, as appropriate in the context of the disclosure. All references to a certain year in this report are to the Company’s fiscal year ended September 30 of that year, unless otherwise noted.

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Part I. Financial Information

Item 1. Financial Statements

National Fuel Gas Company

Consolidated Statements of Income and Earnings

Reinvested in the Business

(Unaudited)

	Three Months Ended June 30,		Nine Months Ended June 30,	
(Thousands of Dollars, Except Per Common Share Amounts)	2013	2012	2013	2012
INCOME				
Operating Revenues	$ 440,008	$ 328,861	$ 1,490,688	$ 1,313,593
Operating Expenses				
Purchased Gas	95,164	50,160	426,900	390,889
Operation and Maintenance	108,497	93,749	338,533	311,857
Property, Franchise and Other Taxes	21,201	20,432	63,550	70,138
Depreciation, Depletion and Amortization	88,142	74,227	240,503	199,925
	313,004	238,568	1,069,486	972,809
Operating Income	127,004	90,293	421,202	340,784
Other Income (Expense):				
Interest Income	317	390	1,844	1,686
Other Income	1,163	1,086	3,666	4,076
Interest Expense on Long-Term Debt	(22,998)	(21,529)	(67,232)	(60,594)
Other Interest Expense	(1,303)	(828)	(2,898)	(2,851)
Income Before Income Taxes	104,183	69,412	356,582	283,101
Income Tax Expense	45,688	26,228	144,423	111,826
Net Income Available for Common Stock	58,495	43,184	212,159	171,275

EARNINGS REINVESTED IN THE BUSINESS

Balance at Beginning of Period	1,398,999	1,275,107	1,306,284	1,206,022
	1,457,494	1,318,291	1,518,443	1,377,297
Dividends on Common Stock	(31,346)	(30,393)	(92,295)	(89,399)
Balance at June 30	$ 1,426,148	$ 1,287,898	$ 1,426,148	$ 1,287,898
Earnings Per Common Share:				
Basic:				
Net Income Available for Common Stock	$ 0.70	$ 0.52	$ 2.54	$ 2.06
Diluted:				
Net Income Available for Common Stock	$ 0.69	$ 0.52	$ 2.52	$ 2.05
Weighted Average Common Shares Outstanding:				
Used in Basic Calculation	83,557,968	83,227,602	83,481,849	83,068,083
Used in Diluted Calculation	84,325,465	83,674,823	84,242,128	83,690,436
Dividends Per Common Share:				
Dividends Declared	$ 0.375	$ 0.365	$ 1.105	$ 1.075

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Statements of Comprehensive Income

(Unaudited)

(Thousands of Dollars)	Three Months Ended June 30, 2013	2012	Nine Months Ended June 30, 2013	2012
Net Income Available for Common Stock	$ 58,495	$ 43,184	$ 212,159	$ 171,275
Other Comprehensive Income (Loss), Before Tax:				
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	331	(1,870)	3,104	1,959
Unrealized Gain on Derivative Financial Instruments Arising During the Period	101,866	30,432	89,865	47,085
Reclassification Adjustment for Realized Gains on Derivative Financial Instruments in Net Income	(1,885)	(21,599)	(23,973)	(49,649)
Other Comprehensive Income (Loss), Before Tax	100,312	6,963	68,996	(605)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	123	(701)	1,160	723
Income Tax Expense Related to Unrealized Gain on Derivative Financial Instruments Arising During the Period	42,566	12,688	37,490	14,346
Reclassification Adjustment for Income Tax Expense on Realized Gains from Derivative Financial Instruments In Net Income	(791)	(8,973)	(10,065)	(15,433)
Income Taxes – Net	41,898	3,014	28,585	(364)
Other Comprehensive Income (Loss)	58,414	3,949	40,411	(241)
Comprehensive Income	$ 116,909	$ 47,133	$ 252,570	$ 171,034

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Balance Sheets

(Unaudited)

	June 30, 2013	September 30, 2012
(Thousands of Dollars)		
ASSETS		
Property, Plant and Equipment	$ 7,102,369	$ 6,615,813
Less - Accumulated Depreciation, Depletion and Amortization	2,088,337	1,876,010
	5,014,032	4,739,803
Current Assets		
Cash and Temporary Cash Investments	134,582	74,494
Hedging Collateral Deposits	694	364
Receivables – Net of Allowance for Uncollectible Accounts of $34,887 and $30,317, Respectively	165,047	115,818
Unbilled Utility Revenue	13,643	19,652
Gas Stored Underground	22,180	49,795
Materials and Supplies - at average cost	31,641	28,577
Other Current Assets	46,205	56,121
Deferred Income Taxes	15,148	10,755
	429,140	355,576
Other Assets		
Recoverable Future Taxes	152,122	150,941
Unamortized Debt Expense	17,227	13,409
Other Regulatory Assets	556,449	546,851
Deferred Charges	8,051	7,591
Other Investments	93,749	86,774
Goodwill	5,476	5,476

Fair Value of Derivative Financial Instruments	65,170	27,616
Other	2,524	1,105
	900,768	839,763
Total Assets	$ 6,343,940	$ 5,935,142

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Balance Sheets

(Unaudited)

(Thousands of Dollars)	June 30, 2013	September 30, 2012
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued		
And Outstanding – 83,587,858 Shares and		
83,330,140 Shares, Respectively	$ 83,588	$ 83,330
Paid in Capital	686,038	669,501
Earnings Reinvested in the Business	1,426,148	1,306,284
Accumulated Other Comprehensive Loss	(58,609)	(99,020)
Total Comprehensive Shareholders' Equity	2,137,165	1,960,095
Long-Term Debt, Net of Current Portion	1,649,000	1,149,000
Total Capitalization	3,786,165	3,109,095
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	-	171,000
Current Portion of Long-Term Debt	-	250,000
Accounts Payable	77,466	87,985
Amounts Payable to Customers	12,386	19,964
Dividends Payable	31,346	30,416
Interest Payable on Long-Term Debt	18,976	29,491
Customer Advances	246	24,055
Customer Security Deposits	16,830	17,942
Other Accruals and Current Liabilities	109,933	79,099
Fair Value of Derivative Financial Instruments	2,217	24,527
	269,400	734,479
Deferred Credits		
Deferred Income Taxes	1,237,727	1,065,757
Taxes Refundable to Customers	65,069	66,392
Unamortized Investment Tax Credit	1,685	2,005

Cost of Removal Regulatory Liability	151,846	139,611
Other Regulatory Liabilities	33,247	21,014
Pension and Other Post-Retirement Liabilities	511,516	516,197
Asset Retirement Obligations	126,879	119,246
Other Deferred Credits	160,406	161,346
	2,288,375	2,091,568
Commitments and Contingencies	-	-
Total Capitalization and Liabilities	$ 6,343,940	$ 5,935,142

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Statements of Cash Flows

(Unaudited)

(Thousands of Dollars)	Nine Months Ended June 30, 2013	2012
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$ 212,159	$ 171,275
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	240,503	199,925
Deferred Income Taxes	141,007	104,948
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(4,314)	(1,511)
Other	19,744	6,618
Change in:		
Hedging Collateral Deposits	(330)	16,309
Receivables and Unbilled Utility Revenue	(43,138)	23,008
Gas Stored Underground and Materials and Supplies	24,551	30,853
Unrecovered Purchased Gas Costs	-	(2,100)
Other Current Assets	14,228	18,190
Accounts Payable	11,241	(5,825)
Amounts Payable to Customers	(7,578)	2,242
Customer Advances	(23,809)	(19,328)
Customer Security Deposits	(1,112)	(474)
Other Accruals and Current Liabilities	3,534	17,083
Other Assets	(5,010)	(1,538)
Other Liabilities	5,557	14,080
Net Cash Provided by Operating Activities	587,233	573,755
INVESTING ACTIVITIES		
Capital Expenditures	(513,399)	(809,661)
Other	(3,885)	(1,267)
Net Cash Used in Investing Activities	(517,284)	(810,928)

FINANCING ACTIVITIES		
Changes in Notes Payable to Banks and Commercial Paper	(171,000)	30,200
Excess Tax Benefits Associated with Stock-Based Compensation Awards	4,314	1,511
Net Proceeds from Issuance of Long-Term Debt	495,415	496,085
Reduction of Long-Term Debt	(250,000)	(150,000)
Dividends Paid on Common Stock	(91,364)	(88,404)
Net Proceeds from Issuance of Common Stock	2,774	8,168
Net Cash Provided by (Used in) Financing Activities	(9,861)	297,560
Net Increase in Cash and Temporary Cash Investments	60,088	60,387
Cash and Temporary Cash Investments at October 1	74,494	80,428
Cash and Temporary Cash Investments at June 30	$ 134,582	$ 140,815

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Notes to Condensed Consolidated Financial Statements

(Unaudited)

Note 1 - Summary of Significant Accounting Policies

Principles of Consolidation. The Company consolidates all entities in which it has a controlling financial interest. All significant intercompany balances and transactions are eliminated.

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

Reclassifications and Revisions. Certain prior year amounts have been reclassified to conform with current year presentation.

Revisions were made on the Consolidated Statement of Cash Flows for the nine months ended June 30, 2012 to reflect non-cash investing activities embedded in Accounts Payable on the Consolidated Balance Sheets at June 30, 2012 and September 30, 2011. These revisions increased the operating cash flows related to the change in Accounts Payable for the nine months ended June 30, 2012 by $32.8 million and decreased investing cash flows related to Capital Expenditures by the same amounts.

In the subsequent period, revisions will be made on the Consolidated Statement of Cash Flows for the fiscal years ended September 30, 2012 and September 30, 2011 to reflect non-cash investing activities embedded in Accounts Payable on the Consolidated Balance Sheets for the respective periods. The revisions for the fiscal years ended September 30, 2012 and September 30, 2011 will decrease operating cash flows by $1.8 million and $6.6 million, respectively, and increase investing cash flows related to Capital Expenditures by the same amounts. The revisions in the Consolidated Statement of Cash Flows noted above represent errors that are not deemed material, individually or in the aggregate, to the prior period consolidated financial statements.

Earnings for Interim Periods. The Company, in its opinion, has included all adjustments (which consist of only normally recurring adjustments, unless otherwise disclosed in this Form 10-Q) that are necessary for a fair statement of the results of operations for the reported periods. The consolidated financial statements and notes thereto, included herein, should be read in conjunction with the financial statements and notes for the years ended September 30, 2012, 2011 and 2010 that are included in the Company's 2012 Form 10-K. The consolidated financial statements for the year ended September 30, 2013 will be audited by the Company's independent registered public accounting firm after the end of the fiscal year.

The earnings for the nine months ended June 30, 2013 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2013. Most of the business of the Utility and Energy Marketing segments is seasonal in nature and is influenced by weather conditions. Due to the seasonal nature of the heating business in the Utility and Energy Marketing segments, earnings during the winter months normally represent a substantial part of the earnings that those segments are expected to achieve for the entire fiscal year. The Company’s business segments are discussed more fully in Note 7 – Business Segment Information.

Consolidated Statement of Cash Flows. For purposes of the Consolidated Statement of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of generally three months or less to be cash equivalents.

The Company has accounts payable and accrued liabilities recorded on its Consolidated Balance Sheets that are related to capital expenditures. These amounts represent non-cash investing activities at the balance sheet date. Accordingly, they are excluded from the Consolidated Statement of Cash Flows when they are recorded as liabilities and included in the Consolidated Statement of Cash Flows when they are paid in the subsequent period. The following table summarizes the Company’s non-cash capital expenditures recorded as Accounts Payable and Other Accruals and Current Liabilities on the Consolidated Balance Sheet:

	At June 30,		At September 30,	
	2013	2012	2012	2011
	(Thousands)			
Non-cash Capital Expenditures	$ 58,632	$ 118,624	$ 67,503	$ 125,115

Hedging Collateral Deposits. This is an account title for cash held in margin accounts funded by the Company to serve as collateral for hedging positions. The Company had hedging collateral deposits of $0.7 million and $0.4 million related to its exchange-traded futures contracts at June 30, 2013 and September 30, 2012, respectively. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instruments liability or asset balances.

Gas Stored Underground - Current. In the Utility segment, gas stored underground – current is carried at lower of cost or market, on a LIFO method. Gas stored underground – current normally declines during the first and second quarters of the year and is replenished during the third and fourth quarters. In the Utility segment, the current cost of replacing gas withdrawn from storage is recorded in the Consolidated Statements of Income and a reserve for gas replacement is recorded in the Consolidated Balance Sheets under the caption "Other Accruals and Current Liabilities." Such reserve, which amounted to $22.0 million at June 30, 2013, is reduced to zero by September 30 of each year as the inventory is replenished.

Property, Plant and Equipment. In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Under this methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center.

Capitalized costs include costs related to unproved properties, which are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. Such costs amounted to $143.8 million and $146.1 million at June 30, 2013 and September 30, 2012, respectively. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. At June 30, 2013, the ceiling exceeded the book value of the oil and gas properties by approximately $199.1 million.

Accumulated Other Comprehensive Loss. The components of Accumulated Other Comprehensive Loss, net of related tax effect, are as follows (in thousands):

	At June 30, 2013	At September 30, 2012
Funded Status of the Pension and Other Post-Retirement Benefit Plans	$ (100,561)	$ (100,561)
Net Unrealized Gain (Loss) on Derivative Financial Instruments	36,865	(1,602)
Net Unrealized Gain on Securities Available for Sale	5,087	3,143
Accumulated Other Comprehensive Loss	$ (58,609)	$ (99,020)

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Other Current Assets. The components of the Company's Other Current Assets are as follows (in thousands):

	At June 30, 2013	At September 30, 2012
Prepayments	$ 10,472	$ 8,316
Prepaid Property and Other Taxes	10,461	14,455
Federal Income Taxes Receivable	-	268
State Income Taxes Receivable	1,058	2,065
Fair Values of Firm Commitments	1,384	1,291
Regulatory Assets	22,830	29,726
	$ 46,205	$ 56,121

Other Accruals and Current Liabilities. The components of the Company's Other Accruals and Current Liabilities are as follows (in thousands):

	At June 30, 2013	At September 30, 2012
Accrued Capital Expenditures	$ 49,348	$ 36,460
Regulatory Liabilities	13,318	18,289
Reserve for Gas Replacement	22,032	-
Other	25,235	24,350
	$ 109,933	$ 79,099

Earnings Per Common Share. Basic earnings per common share is computed by dividing net income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options, SARs and restricted stock units. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these securities as determined using the Treasury Stock Method. Stock options, SARs and restricted stock units that are antidilutive are excluded from the calculation of diluted earnings per common share. There were 180,552 and 196,121 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2013, respectively. There were 976,870 and 833,170 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2012, respectively.

Stock-Based Compensation. During the nine months ended June 30, 2013, the Company granted 412,970 SARs having a weighted average exercise price of $53.05 per share. The weighted average grant date fair value of these SARs was $10.66 per share. These SARs may be settled in cash, in shares of common stock of the Company, or in a combination of cash and shares of common stock of the Company, as determined by the Company. These SARs are considered equity awards under the current authoritative guidance for stock-based compensation. The accounting for those SARs is the same as the accounting for stock options. The SARs granted during the nine months ended June 30, 2013 vest and become exercisable annually in one-third increments. The weighted average grant date fair value of these SARs granted during the nine months ended June 30, 2013 was estimated on the date of grant using the same accounting treatment that is applied for stock options. There were no stock options granted during the nine months ended June 30, 2013.

The Company granted 255,604 performance based restricted stock units during the nine months ended June 30, 2013. The weighted average fair value of such performance based restricted stock units was $49.51 per share for the nine months ended June 30, 2013. The performance based restricted stock units granted during the nine months ended June 30, 2013 must meet a performance condition over the performance cycle of October 1, 2012 to September 30, 2015. The performance condition over the performance cycle, generally stated, is the Company's total return on capital as compared to the same metric for companies in the Natural Gas Distribution and Integrated Natural Gas Companies group as calculated and reported in the Monthly Utility Reports of AUS, Inc., a leading industry consultant. The number of performance based restricted stock units that will vest will depend upon the Company's performance relative to the report group and not upon the absolute level of return achieved by the Company. The Company also granted 39,700 non-performance based restricted stock units during the nine months ended June 30, 2013. The weighted average fair value of such non-performance based restricted stock units was $50.13 per share for the nine months ended June 30, 2013.

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Restricted stock units, both performance based and non-performance based, represent the right to receive shares of common stock of the Company (or the equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company) at the end of a specified time period. The performance based and non-performance based restricted stock units do not entitle the participant to receive dividends during the vesting period. The accounting for performance based and non-performance based restricted stock units is the same as the accounting for restricted share awards, except that the fair value at the date of grant of the restricted stock units must be reduced by the present value of forgone dividends over the vesting term of the award. There were no restricted share awards granted during the nine months ended June 30, 2013.

New Authoritative Accounting and Financial Reporting Guidance. In December 2011, the FASB issued authoritative guidance requiring enhanced disclosures regarding offsetting assets and liabilities. Companies are required to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2014 and is not expected to have a significant impact on the Company's financial statements.

In February 2013, the FASB issued authoritative guidance requiring enhanced disclosures regarding the reporting of amounts reclassified out of accumulated other comprehensive income. The authoritative guidance requires parenthetical disclosure on the face of the financial statements or a single footnote that would provide more detail about the components of reclassification adjustments that are reclassified in their entirety to net income. If a component of a reclassification adjustment is not reclassified in its entirety to net income, a cross reference would be made to the footnote disclosure that provides a more thorough discussion of the component involved in that reclassification adjustment. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2014. The Company does not expect this guidance to have a material impact.

Note 2 – Fair Value Measurements

The FASB authoritative guidance regarding fair value measurements establishes a fair-value hierarchy and prioritizes the inputs used in valuation techniques that measure fair value. Those inputs are prioritized into three levels. Level 1 inputs are unadjusted quoted prices in active markets for assets or liabilities that the Company can access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly at the measurement date. Level 3 inputs are unobservable inputs for the asset or liability at the measurement date. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of June 30, 2013 and September 30, 2012. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

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Recurring Fair Value Measures	At fair value as of June 30, 2013				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
Assets:					
Cash Equivalents – Money Market Mutual Funds	$ 122,024	$ -	$ -	$ -	$ 122,024
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	2,252	-	-	(1,806)	446
Over the Counter Swaps – Gas	-	63,255	-	(5,093)	58,162
Over the Counter Swaps – Oil	-	9,078	17	(3,260)	5,835
Other Investments:					
Balanced Equity Mutual Fund	30,125	-	-	-	30,125
Common Stock – Financial Services Industry	6,331	-	-	-	6,331
Other Common Stock	295	-	-	-	295
Hedging Collateral Deposits	694	-	-	-	694
Total	$ 161,721	$ 72,333	$ 17	$ (10,159)	$ 223,912
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$ 1,806	$ -	$ -	$ (1,806)	$ -
Over the Counter Swaps – Gas	-	2,626	-	(5,093)	(2,467)
Over the Counter Swaps – Oil	-	-	7,944	(3,260)	4,684
Total	$ 1,806	$ 2,626	$ 7,944	$ (10,159)	$ 2,217
Total Net Assets/(Liabilities)	$ 159,915	$ 69,707	$ (7,927)	$ -	$ 221,695

Recurring Fair Value Measures	At fair value as of September 30, 2012				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
Assets:					
Cash Equivalents – Money Market Mutual Funds	$ 46,113	$ -	$ -	$ -	$ 46,113

Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	4,348	-	-	(2,760)	1,588
Over the Counter Swaps – Gas	-	41,751	-	(15,723)	26,028
Over the Counter Swaps – Oil	-	-	559	(559)	-
Other Investments:					
Balanced Equity Mutual Fund	24,767	-	-	-	24,767
Common Stock – Financial Services Industry	4,758	-	-	-	4,758
Other Common Stock	272	-	-	-	272
Hedging Collateral Deposits	364	-	-	-	364
Total	$ 80,622	$ 41,751	$ 559	$ (19,042)	$ 103,890
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$ 2,760	$ -	$ -	$ (2,760)	$ -
Over the Counter Swaps – Gas	-	19,932	-	(15,723)	4,209
Over the Counter Swaps – Oil	-	654	20,223	(559)	20,318
Total	$ 2,760	$ 20,586	$ 20,223	$ (19,042)	$ 24,527
Total Net Assets/(Liabilities)	$ 77,862	$ 21,165	$ (19,664)	$ -	$ 79,363

(1) Netting Adjustments represent the impact of legally-enforceable master netting arrangements that allow the Company to net gain and loss positions held with the same counterparties. The net asset or net liability for each counterparty is recorded as an asset or liability on the Company’s balance sheet. In the tables above, presenting asset and liability information by gas and oil positions may result in negative assets or negative liabilities in Total column when a counterparty has issued both gas and oil swaps to the Company.

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Derivative Financial Instruments

At June 30, 2013 and September 30, 2012, the derivative financial instruments reported in Level 1 consist of natural gas NYMEX futures contracts used in the Company's Energy Marketing segment. Hedging collateral deposits of $0.7 million (at June 30, 2013) and $0.4 million (at September 30, 2012), which are associated with these futures contracts, have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 at June 30, 2013 and September 30, 2012 consist of natural gas price swap agreements used in the Company's Exploration and Production and Energy Marketing segments and a portion of the crude oil price swap agreements used in the Company's Exploration and Production segment. The fair value of the Level 2 price swap agreements is based on an internal, discounted cash flow model that uses observable inputs (i.e. LIBOR based discount rates and basis differential information, if applicable, at active natural gas and crude oil trading markets). The derivative financial instruments reported in Level 3 consist of a portion of the Company's Exploration and Production segment's crude oil price swap agreements at June 30, 2013 and September 30, 2012. The fair value of the Level 3 crude oil price swap agreements is based on an internal, discounted cash flow model that uses both observable (i.e. LIBOR based discount rates) and unobservable inputs (i.e. basis differential information of crude oil trading markets with low trading volume).

The significant unobservable input used in the fair value measurement of a portion of the Company's over-the-counter crude oil swaps is the basis differential between Midway Sunset oil and NYMEX contracts. Significant changes in the assumed basis differential could result in a significant change in value of the derivative financial instruments. At June 30, 2013, it was assumed that Midway Sunset oil was valued at 109.3% of the value of oil priced at NYMEX. This is based on a historical twelve month average of Midway Sunset oil sales verses NYMEX settlements. During this twelve-month period, the price of Midway Sunset oil ranged from 102.3% to 112.4% of NYMEX. If the basis differential between Midway Sunset oil and NYMEX contracts used in the fair value measurement calculation at June 30, 2013 had been 10 percentage points lower, the fair value of the Level 3 crude oil price swap agreements would have changed from a net liability of $7.9 million to a net asset of $1.3 million. If the basis differential between Midway Sunset oil and NYMEX contracts used in the fair value measurement at June 30, 2013 had been 10 percentage points higher, the fair value measurement of the Level 3 crude oil price swap agreements liability would have been approximately $9.5 million higher. These calculated amounts are based solely on basis differential changes and do not take into account any other changes to the fair value measurement calculation.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At June 30, 2013, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty (for an asset) or the Company's (for a liability) credit default swaps rates.

The tables listed below provide reconciliations of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3 for the quarters and nine months ended June 30, 2013 and 2012, respectively. For the quarters and nine months ended June 30, 2013 and June 30, 2012, no transfers in or out of Level 1 or Level 2 occurred. There were no purchases or sales of derivative financial instruments during the periods presented in the tables below. All settlements of the derivative financial instruments are reflected in the Gains/Losses Realized and Included in Earnings column of the tables below.

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)		Total Gains/Losses			
	April 1, 2013	(Gains)/ Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2013
Derivative Financial Instruments[2]	$ (16,606)	$ 2,471 (1)	$ 6,208	$ -	$ (7,927)

[1] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended June 30, 2013.

[2] Derivative Financial Instruments are shown on a net basis.

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Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)		Total Gains/Losses			
	October 1, 2012	(Gains)/ Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2013
Derivative Financial Instruments[2]	$ (19,664)	$ 9,271 (1)	$ 2,466	$ -	$ (7,927)

[1] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the nine months ended June 30, 2013.

[2] Derivative Financial Instruments are shown on a net basis.

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)		Total Gains/Losses			
	April 1, 2012	(Gains)/ Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included In Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2012
Derivative Financial Instruments[2]	$ (68,754)	$ 10,392 (1)	$ 41,814	$ -	$ (16,548)

[1] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended June 30, 2012.

[2] Derivative Financial Instruments are shown on a net basis.

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)	October 1, 2011	Total Gains/Losses (Gains)/ Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included In Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2012
Derivative Financial Instruments(2)	$ (5,410)	$ 36,526 (1)	$ (47,664)	$ -	$ (16,548)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the nine months ended June 30, 2012.

(2) Derivative Financial Instruments are shown on a net basis.

Note 3 – Financial Instruments

Long-Term Debt. The fair market value of the Company's debt, as presented in the table below, was determined using a discounted cash flow model, which incorporates the Company's credit ratings and current market conditions in determining the yield, and subsequently, the fair market value of the debt. Based on these criteria, the fair market value of long-term debt, including current portion, was as follows (in thousands):

	June 30, 2013		September 30, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$ 1,649,000	$ 1,790,040	$ 1,399,000	$ 1,623,847

The fair value amounts are not intended to reflect principal amounts that the Company will ultimately be required to pay. Carrying amounts for other financial instruments recorded on the Company's Consolidated Balance Sheets approximate fair value. The fair value of long-term debt was calculated using observable inputs (U.S. Treasuries/LIBOR

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for the risk free component and company specific credit spread information – generally obtained from recent trade activity in the debt). As such, the Company considers the debt to be Level 2.

Temporary cash investments, notes payable to banks and commercial paper are stated at cost. Temporary cash investments are considered Level 1, while notes payable to banks and commercial paper are considered to be Level 2. Given the short-term nature of the notes payable to banks and commercial paper, the Company believes cost is a reasonable approximation of fair value.

Other Investments. Investments in life insurance are stated at their cash surrender values or net present value as discussed below. Investments in an equity mutual fund and the stock of an insurance company (marketable equity securities), as discussed below, are stated at fair value based on quoted market prices.

Other investments include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity securities. The values of the insurance contracts amounted to $57.0 million at June 30, 2013 and September 30, 2012. The fair value of the equity mutual fund was $30.1 million at June 30, 2013 and $24.8 million at September 30, 2012. The gross unrealized gain on this equity mutual fund was $4.1 million at June 30, 2013 and $2.6 million at September 30, 2012. The fair value of the stock of an insurance company was $6.3 million at June 30, 2013 and $4.8 million at September 30, 2012. The gross unrealized gain on this stock was $3.9 million at June 30, 2013 and $2.3 million at September 30, 2012. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments. The Company uses or has used derivative instruments to manage commodity price risk in the Exploration and Production, Energy Marketing, and Pipeline and Storage segments. The Company enters into futures contracts and over-the-counter swap agreements for natural gas and crude oil to manage the price risk associated with forecasted sales of gas and oil. The Company also enters into futures contracts and swaps to manage the risk associated with forecasted gas purchases, forecasted gas sales, storage of gas, withdrawal of gas from storage to meet customer demand and the potential decline in the value of gas held in storage. The duration of the Company's hedges does not typically exceed 5 years.

The Company has presented its net derivative assets and liabilities as "Fair Value of Derivative Financial Instruments" on its Consolidated Balance Sheets at June 30, 2013 and September 30, 2012. All of the derivative financial instruments reported on those line items relate to commodity contracts.

Cash flow hedges

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income (loss) and reclassified into earnings in the period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

As of June 30, 2013, the Company's Exploration and Production segment had the following commodity derivative contracts (swaps) outstanding to hedge forecasted sales (where the Company uses short positions (i.e. positions that pay-off in the event of commodity price decline) to mitigate the risk of decreasing revenues and earnings):

Commodity	Units
Natural Gas	208.0 Bcf (all short positions)
Crude Oil	4,134,000 Bbls (all short positions)

As of June 30, 2013, the Company's Energy Marketing segment had the following commodity derivative contracts (futures contracts and swaps) outstanding to hedge forecasted sales (where the Company uses short positions to mitigate the risk associated with natural gas price decreases and its impact on decreasing revenues and earnings) and, when applicable, purchases (where the Company uses long positions (i.e. positions that pay-off in the event of commodity price increases) to mitigate the risk of increasing natural gas prices, which would lead to increased purchased gas expense and decreased earnings):

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Commodity	Units
Natural Gas	7.1 Bcf (5.6 Bcf short positions (mostly forecasted storage withdrawals) and 1.5 Bcf long positions (mostly forecasted storage injections))

As of June 30, 2013, the Company's Exploration and Production segment had $61.6 million ($35.8 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $40.1 million ($23.3 million after tax) of such unrealized gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the expected sales of the underlying commodities occur.

As of June 30, 2013, the Company's Energy Marketing segment had $1.7 million ($1.1 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that the full amount will be reclassified into the Consolidated Statement of Income (Loss) within the next 12 months as the expected sales of the underlying commodity occurs.

Refer to Note 1, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain (loss) pertaining to derivative financial instruments for the Exploration and Production and Energy Marketing segments.

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended June 30, 2013 and 2012 (Thousands of Dollars)

	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on	Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet	Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective

Derivatives in Cash Flow Hedging Relationships	the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Three Months Ended June 30, 2013	2012	Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	into the Consolidated Statement of Income (Effective Portion) for the Three Months Ended June 30, 2013	2012	Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Portion and Amount Excluded from Effectiveness Testing) for the Three Months Ended June 30, 2013	2012
Commodity Contracts – Exploration & Production segment	$ 99,987	$ 31,358	Operating Revenue	$ 1,504	$ 20,643	Operating Revenue	$ 456	$ -
Commodity Contracts – Energy Marketing segment	$ 1,879	$ (201)	Purchased Gas	$ (75)	$ 956	Not Applicable	$ -	$ -
Commodity Contracts – Pipeline & Storage segment(1)	$ -	$ (725)	Operating Revenue	$ -	$ -	Not Applicable	$ -	$ -
Total	$ 101,866	$ 30,432		$ 1,429	$ 21,599		$ 456	$ -

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The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Nine Months Ended June 30, 2013 and 2012 (Thousands of Dollars)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Nine Months Ended June 30, 2013	2012	Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Nine Months Ended June 30, 2013	2012	Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Nine Months Ended June 30, 2013	2012
Commodity Contracts – Exploration & Production segment	$ 86,237	$ 40,897	Operating Revenue	$ 25,550	$ 38,633	Not Applicable	$ -	$ -
Commodity Contracts – Energy Marketing segment	$ 3,628	$ 6,337	Purchased Gas	$ (905)	$ 10,440	Not Applicable	$ -	$ -
Commodity Contracts – Pipeline & Storage segment(1)	$ -	$ (149)	Operating Revenue	$ (672)	$ 576	Not Applicable	$ -	$ -
Total	$ 89,865	$ 47,085		$ 23,973	$ 49,649		$ -	$ -

(1) There were no open hedging positions at June 30, 2013.

Fair value hedges

The Company's Energy Marketing segment utilizes fair value hedges to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in the value of certain natural gas held in storage. With respect to fixed price sales commitments, the Company enters into long positions to mitigate the risk of price increases for natural gas supplies that could occur after the Company enters into fixed price sales agreements with its customers. With respect to fixed price purchase commitments, the Company enters into short positions to mitigate the risk of price decreases that could occur after the Company locks into fixed price purchase deals with its suppliers. With respect to storage hedges, the Company enters into short positions to mitigate the risk of price decreases that could result in a lower of cost or market writedown of the value of natural gas in storage that is recorded in the Company's financial statements. As of June 30, 2013, the Company's Energy Marketing segment had fair value hedges covering approximately 7.8 Bcf (6.8 Bcf of fixed price sales commitments (mostly long positions) and 1.0 Bcf of fixed price purchase commitments (mostly short positions)). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

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Derivatives in Fair Value Hedging Relationships – Energy Marketing segment	Location of Gain or (Loss) on Derivative and Hedged Item Recognized in the Consolidated Statement of Income	Amount of Gain or (Loss) on Derivative Recognized in the Consolidated Statement of Income for the Nine Months Ended June 30, 2013 (In Thousands)	Amount of Gain or (Loss) on the Hedged Item Recognized in the Consolidated Statement of Income for the Nine Months Ended June 30, 2013 (In Thousands)
Commodity Contracts – Hedge of fixed price sales commitments of natural gas	Operating Revenues	$ (1,720)	$ 1,720
Commodity Contracts – Hedge of fixed price purchase commitments of natural gas	Purchased Gas	$ (148)	$ 148
Commodity Contracts – Hedge of natural gas held in storage	Purchased Gas	$ 10	$ (10)
		$ (1,858)	$ 1,858

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company’s counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with thirteen counterparties of which eleven are in a net gain position. On average, the Company had $5.8 million of credit exposure per counterparty in a gain position at June 30, 2013. The maximum credit exposure per counterparty in a gain position at June 30, 2013 was $12.2 million. As of June 30, 2013, the Company had not received any collateral from the counterparties. The Company’s gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral, nor had the counterparties’ credit ratings declined to levels at which the counterparties were required to post collateral.

As of June 30, 2013, eleven of the thirteen counterparties to the Company's outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk related contingency feature. In the event the Company's credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company's credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company's outstanding derivative instrument contracts were in a liability position (or if the current liability were larger) and/or the Company's credit rating declined, then additional hedging collateral deposits may be required. At June 30, 2013, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $48.8 million according to the Company's internal model (discussed in Note 2 — Fair Value Measurements). At June 30, 2013, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $2.2 million according to the Company's internal model (discussed in Note 2 — Fair Value Measurements). For its over-the-counter swap agreements, the Company was not required to post any hedging collateral deposits at June 30, 2013.

For its exchange traded futures contracts, which are in an asset position, the Company was required to post $0.7 million in hedging collateral deposits as of June 30, 2013. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

The Company's requirement to post hedging collateral deposits is based on the fair value determined by the Company's counterparties, which may differ from the Company's assessment of fair value. Hedging collateral deposits may also include closed derivative positions in which the broker has not cleared the cash from the account to offset the

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derivative liability. The Company records liabilities related to closed derivative positions in Other Accruals and Current Liabilities on the Consolidated Balance Sheet. These liabilities are relieved when the broker clears the cash from the hedging collateral deposit account. This is discussed in Note 1 under Hedging Collateral Deposits.

Note 4 - Income Taxes

The components of federal and state income taxes included in the Consolidated Statements of Income are as follows (in thousands):

	Nine Months Ended June 30,	
	2013	2012
Current Income Taxes		
Federal	$ (518)	$ -
State	3,934	6,878
Deferred Income Taxes		
Federal	105,362	85,910
State	35,645	19,038
	144,423	111,826
Deferred Investment Tax Credit	(320)	(436)
Total Income Taxes	$ 144,103	$ 111,390
Presented as Follows:		
Other Income	(320)	(436)
Income Tax Expense	144,423	111,826
Total Income Taxes	$ 144,103	$ 111,390

Total income taxes as reported differ from the amounts that were computed by applying the federal income tax rate to income before income taxes. The following is a reconciliation of this difference (in thousands):

	Nine Months Ended June 30,	
	2013	2012
U.S. Income Before Income Taxes	$ 356,262	$ 282,665
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$ 124,692	$ 98,933
Increase (Reduction) in Taxes Resulting from:		
State Income Taxes	25,726	16,845
Miscellaneous	(6,315)	(4,388)
Total Income Taxes	$ 144,103	$ 111,390

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Significant components of the Company's deferred tax liabilities and assets were as follows (in thousands):

	At June 30, 2013	At September 30, 2012
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 1,465,567	$ 1,333,574
Pension and Other Post-Retirement Benefit Costs	244,453	236,431
Other	64,365	43,294
Total Deferred Tax Liabilities	1,774,385	1,613,299
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(276,056)	(276,501)
Tax Loss Carryforwards	(194,138)	(198,744)
Other	(81,612)	(83,052)
Total Deferred Tax Assets	(551,806)	(558,297)
Total Net Deferred Income Taxes	$ 1,222,579	$ 1,055,002
Presented as Follows:		
Net Deferred Tax Liability/(Asset) – Current	(15,148)	(10,755)
Net Deferred Tax Liability – Non-Current	1,237,727	1,065,757
Total Net Deferred Income Taxes	$ 1,222,579	$ 1,055,002

During the quarter ended June 30, 2013, there was no change in the balance of unrecognized tax benefits. For nine months ended June 30, 2013, the balance of unrecognized tax benefits decreased by $9.3 million, primarily as a result of favorable settlements with taxing authorities (as discussed below), of which $2.1 million reduced the effective tax rate during the second quarter. Approximately $2.0 million of the remaining balance of unrecognized tax benefits would favorably impact the effective tax rate, if recognized. It is reasonably possible that a reduction of $2.0 million of the balance of uncertain tax positions may occur as a result of potential settlements with taxing authorities within the next twelve months.

As a result of certain realization requirements of the authoritative guidance on stock-based compensation, the table of deferred tax liabilities and assets shown above does not include certain deferred tax assets that arose directly from excess tax deductions related to stock-based compensation. Tax benefits of $4.3 million and $0.6 million relating to the excess stock-based compensation deductions were recorded in Paid in Capital during the nine months ended June 30, 2013 and the year ended September 30, 2012, respectively. Cumulative tax benefits of $33.6 million and $32.7 million remain as of June 30, 2013 and September 30, 2012, respectively, and will be recorded in Paid in Capital in future years when such tax benefits are realized.

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to $65.1 million and $66.4 million at June 30, 2013 and September 30, 2012, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $152.1 million and $150.9 million at June 30, 2013 and September 30, 2012, respectively.

The Internal Revenue Service (IRS) is currently conducting examinations of the Company for fiscal 2012 and fiscal 2013 in accordance with the Compliance Assurance Process (CAP). The CAP audit employs a real time review of the Company's books and tax records by the IRS that is intended to permit issue resolution prior to the filing of the tax return. While the federal statute of limitations remains open for fiscal 2009 and later years, IRS examinations for fiscal 2008 and prior years have been completed and the Company believes such years are effectively settled. During fiscal 2009, consent was received from the IRS National Office approving the Company's application to change its tax method of accounting for certain capitalized costs relating to its utility property. During the quarter ended March 31, 2013, local IRS examiners issued no-change reports for fiscal 2009, fiscal 2010 and fiscal 2011, but have reserved the right to re-examine these years, pending the anticipated issuance of IRS guidance addressing the issue for natural gas utilities. In addition, the Company negotiated a settlement of the fiscal 2011 Research Tax Credit.

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The Company is also subject to various routine state income tax examinations. The Company's principal subsidiaries operate mainly in four states which have statutes of limitations that generally expire between three to four years from the date of filing of the income tax return.

On January 2, 2013, President Obama signed into law the American Taxpayer Relief Act of 2012 (the Relief Act). The Relief Act does not have a material effect on the Company's financial statements.

Note 5 - Capitalization

Common Stock. During the nine months ended June 30, 2013, the Company issued 457,091 original issue shares of common stock as a result of stock option and SARs exercises. In addition, the Company issued 97,554 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan. The Company also issued 12,380 original issue shares of common stock to the non-employee directors of the Company who receive compensation under the Company's 2009 Non-Employee Director Equity Compensation Plan, as partial consideration for the directors' services during the nine months ended June 30, 2013. Holders of stock options, SARs or restricted stock will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During the nine months ended June 30, 2013, 309,307 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

Current Portion of Long-Term Debt. Current Portion of Long-Term Debt at September 30, 2012 consisted of $250 million of 5.25% notes that matured in March 2013. None of the Company's long-term debt at June 30, 2013 will mature within the following twelve-month period.

Long-Term Debt. On February 15, 2013, the Company issued $500.0 million of 3.75% notes due March 1, 2023. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $495.4 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used to refund the $250 million of 5.25% notes that matured in March 2013, as well as for general corporate purposes, including the reduction of short-term debt.

Note 6 - Commitments and Contingencies

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory policies and procedures. It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs.

The Company has agreed with the NYDEC to remediate a former manufactured gas plant site located in New York. In February 2009, the Company received approval from the NYDEC of a Remedial Design Work Plan (RDWP) for this site. In October 2010, the Company submitted a RDWP addendum to conduct additional Preliminary Design Investigation field activities necessary to design a successful remediation. As a result of this work, the Company submitted to the NYDEC a proposal to amend the NYDEC's Record of Decision remedy for the site. In April 2013, the NYDEC approved the Company's proposed amendment. Final remedial design work for the site has begun. An estimated minimum liability for remediation of this site of $13.9 million has been recorded.

At June 30, 2013, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites (including the former manufactured gas plant site discussed above) will be approximately $16.8 million. This estimated liability, which includes the $13.9 million discussed above, has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at June 30, 2013. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 11 years.

The Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental laws and regulations, new information or other factors could have an adverse financial impact on the Company.

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Other. The Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these other matters arising in the normal course of business could have a material effect on earnings and cash flows in the period in which they are resolved, an estimate of the possible loss or range of loss, if any, cannot be made at this time.

Note 7 – Business Segment Information

The Company reports financial results for four segments: Utility, Pipeline and Storage, Exploration and Production, and Energy Marketing. The division of the Company's operations into reportable segments is based upon a combination of factors including differences in products and services, regulatory environment and geographic factors.

The data presented in the tables below reflect financial information for the segments and reconciliations to consolidated amounts. As stated in the 2012 Form 10-K, the Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income. There have not been any changes in the basis of segmentation nor in the basis of measuring segment profit or loss from those used in the Company's 2012 Form 10-K. As for segment assets, there have been significant changes from the segment assets disclosed in the 2012 Form 10-K. A listing of segment assets at June 30, 2013 is shown in the tables below.

Quarter Ended June 30, 2013 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$ 141,257	$ 43,055	$ 195,213	$ 59,128	$ 438,653	$ 1,121	$ 234	$ 440,008
Intersegment Revenues	$ 3,305	$ 21,708	$ -	$ 446	$ 25,459	$ 10,244	$ (35,703)	$ -
Segment Profit:								

Net Income (Loss)	$ 7,630	$ 14,075	$ 31,734	$ 963	$ 54,402	$ 4,499	$ (406)	$ 58,495

Nine Months Ended June 30, 2013 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidate
Revenue from External Customers	$ 653,211	$ 132,897	$ 518,742	$ 182,282	$ 1,487,132	$ 2,898	$ 658	$ 1,490,68
Intersegment Revenues	$ 14,012	$ 68,216	$ -	$ 1,080	$ 83,308	$ 23,622	$ (106,930)	$ -
Segment Profit: Net Income (Loss)	$ 65,024	$ 47,803	$ 86,125	$ 5,741	$ 204,693	$ 9,449	$ (1,983)	$ 212,159

At June 30, 2013 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidate
Segment Assets	$ 2,074,329	$ 1,281,445	$ 2,614,406	$ 69,106	$ 6,039,286	$ 273,048	$ 31,606	$ 6,343,94

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Quarter Ended June 30, 2012 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$ 117,240	$ 36,631	$ 138,549	$ 35,377	$ 327,797	$ 824	$ 240	$ 328,861
Intersegment Revenues	$ 2,703	$ 22,076	$ -	$ 579	$ 25,358	$ 4,307	$ (29,665)	$ -
Segment Profit: Net Income (Loss)	$ 5,096	$ 12,627	$ 21,915	$ 923	$ 40,561	$ 2,815	$ (192)	$ 43,184

Nine Months Ended June 30, 2012 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$ 622,836	$ 113,976	$ 411,449	$ 161,822	$ 1,310,083	$ 2,784	$ 726	$ 1,313,593
Intersegment Revenues	$ 12,643	$ 64,434	$ -	$ 1,135	$ 78,212	$ 10,828	$ (89,040)	$ -
Segment Profit: Net Income (Loss)	$ 52,725	$ 35,428	$ 74,422	$ 4,662	$ 167,237	$ 5,557	$ (1,519)	$ 171,275

Note 8 – Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

Three Months Ended June 30,	Retirement Plan		Other Post-Retirement Benefits	
	2013	2012	2013	2012
Service Cost	$ 3,961	$ 3,551	$ 1,176	$ 1,004
Interest Cost	9,124	10,381	4,803	5,329
Expected Return on Plan Assets	(14,336)	(14,925)	(8,218)	(7,243)
Amortization of Prior Service Cost	60	67	(534)	(534)
Amortization of Transition Amount	-	-	2	3
Amortization of Losses	13,194	9,904	5,223	6,014
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	(3,854)	(2,252)	2,393	718
Net Periodic Benefit Cost	$ 8,149	$ 6,726	$ 4,845	$ 5,291

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Nine Months Ended June 30,

	Retirement Plan		Other Post-Retirement Benefits	
	2013	2012	2013	2012
Service Cost	$ 11,884	$ 10,652	$ 3,529	$ 3,012
Interest Cost	27,373	31,144	14,409	15,986
Expected Return on Plan Assets	(43,009)	(44,776)	(24,654)	(21,728)
Amortization of Prior Service Cost	179	202	(1,604)	(1,604)
Amortization of Transition Amount	-	-	6	8
Amortization of Losses	39,582	29,711	15,669	18,043
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	(5,813)	(1,896)	11,555	7,993
Net Periodic Benefit Cost	$ 30,196	$ 25,037	$ 18,910	$ 21,710

(1) The Company's policy is to record retirement plan and other post-retirement benefit costs in the Utility segment on a volumetric basis to reflect the fact that the Utility segment experiences higher throughput of natural gas in the winter months and lower throughput of natural gas in the summer months.

Employer Contributions. During the nine months ended June 30, 2013, the Company contributed $42.0 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $15.8 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2013, the Company expects to contribute approximately $10.0 million to the Retirement Plan. Changes in the discount rate, other actuarial assumptions, and asset performance could ultimately cause the Company to fund larger amounts to the Retirement Plan in fiscal 2013 in order to be in compliance with the Pension Protection Act of 2006 (as impacted by the Moving Ahead for Progress in the 21st Century Act). In July 2012, the Surface Transportation Extension Act, which is also referred to as the Moving Ahead for Progress in the 21st Century Act (the Act), was passed by Congress and signed by the President. The Act included pension funding stabilization provisions. The Company is continually evaluating its future contributions in light of the provisions of the Act. In the remainder of 2013, the Company expects to contribute approximately $2.2 million to its VEBA trusts and 401(h) accounts.

Note 9 – Regulatory Matters

On March 27, 2013, Distribution Corporation filed a plan ("Plan") with the NYPSC proposing to adopt an "earnings stabilization and sharing mechanism" that would allocate earnings above a rate of return on equity of 9.96% evenly between shareholders and an accounting reserve ("Reserve"). The Reserve would be utilized to stabilize Distribution Corporation's earnings and to fund customer benefit programs. The Plan also proposed to increase capital spending and to aid new customer system expansion efforts. Discussions were held with NYPSC staff and others with respect to the Plan.

In a related development, on April 19, 2013, the NYPSC issued an order directing Distribution Corporation to either agree to make its rates and charges temporary subject to refund effective June 1, 2013, or show cause why its gas rates and charges should not be set on a temporary basis subject to refund (“Order”). The Order recognized Distribution Corporation’s Plan and determined that the Plan did not propose to adjust “existing rates . . . enough to compensate for the imbalance between ratepayer and shareholder interests that has developed since . . . 2007 . . .” Pursuant to the Order, the NYPSC commenced a “temporary rate” proceeding and, following hearings, on June 14, 2013, the NYPSC issued an order making Distribution Corporation’s rates and charges temporary and subject to refund pending the determination of permanent gas rates through further rate proceedings. Exploratory discussions for settlement of Distribution Corporation’s rates and charges were commenced and are expected to continue as the formal case to establish permanent rates proceeds along a parallel path.

In addition to authorizing a “temporary rate” proceeding, the Order also suggested an examination of the applicability of a provision of New York public utility law, PSL §66(20), that provides the NYPSC with stated authority to direct a refund of revenues received by a utility “in excess of its authorized rate of return for a period of twelve months.” On May 17, 2013, Distribution Corporation commenced an action in New York Supreme Court, Erie County, seeking the court’s declaration that PSL §66(20) is unconstitutional and enjoining the NYPSC from issuing any orders or rules under PSL §66(20) or making any attempts to otherwise enforce the statute. On June 20, 2013 and as anticipated, the NYPSC moved to dismiss Distribution Corporation’s complaint. Distribution Corporation is unable to predict the outcome of the proceedings at this time.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Please note that this overview is a high-level summary of items that are discussed in greater detail in subsequent sections of this report.

The Company is a diversified energy holding company that owns a number of subsidiary operating companies, and reports financial results in four reportable business segments. For the quarter ended June 30, 2013 compared to the quarter ended June 30, 2012, the Company experienced an increase in earnings of $15.3 million. For the nine months ended June 30, 2013 compared to the nine months ended June 30, 2012, the Company experienced an increase in earnings of $40.9 million. The earnings increase for both the quarter and nine-month periods ended June 30, 2013 reflect increases in all of the Company’s segments as well as the All Other category. For further discussion of the Company’s earnings, refer to the Results of Operations section below.

The Company’s natural gas reserve base has grown substantially in recent years due to its development of reserves in the Marcellus Shale, a Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York. The Company controls the natural gas interests associated with approximately 775,000 net acres within the Marcellus Shale area, with a majority of the interests held in fee, carrying no royalty and no lease expirations. Natural gas proved developed and undeveloped reserves in the Appalachian region increased from 607 Bcf at September 30, 2011 to 925 Bcf at September 30, 2012. The Company has spent significant amounts of capital in this region related to the development of such reserves. For the nine months ended June 30, 2013, the Company’s Exploration and Production segment had capital expenditures of $312.4 million in the Appalachian region, of which $290.1 million was spent towards the development of the Marcellus Shale. The Company’s fiscal 2013 estimated capital expenditures in the Appalachian region are expected to be approximately $460.0 million.

From a capital resources perspective, the Company has largely been able to meet its capital expenditure needs by using cash from operations as well as both short and long-term debt. In February 2013, the Company issued $500.0 million of 3.75% notes due in March 2023 to refund the $250.0 million of 5.25% notes that matured in March 2013 and to enhance its liquidity position.

The well completion technology referred to as hydraulic fracturing used in conjunction with horizontal drilling continues to be debated. In Pennsylvania, where the Company is focusing its Marcellus Shale development efforts, the permitting and regulatory processes seem to strike a balance between the environmental concerns associated with hydraulic fracturing and the benefits of increased natural gas production. Hydraulic fracturing is a well stimulation technique that has been used for many years and, in the Company’s experience, one that the Company believes has little negative impact to the environment. Nonetheless, the potential for increased state or federal regulation of hydraulic fracturing could impact future costs of drilling in the Marcellus Shale and lead to operational delays or restrictions. There is also the risk that drilling could be prohibited on certain acreage that is prospective for the Marcellus Shale. Please refer to the Risk Factors section of the Company’s 2012 Form 10-K for further discussion.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to "Critical Accounting Estimates" in Item 7 of the Company's 2012 Form 10-K and Item 2 of the Company’s December 31, 2012 and March 31, 2013 Form 10-Qs. There have been no material changes to that disclosure other than as set forth below. The information presented below updates and should be read in conjunction with the critical accounting estimates in those documents.

Oil and Gas Exploration and Development Costs. The Company, in its Exploration and Production segment, follows the full cost method of accounting for determining the book value of its oil and natural gas properties. In accordance with this methodology, the Company is required to perform a quarterly ceiling test. Under the ceiling test, the present value of future revenues from the Company's oil and gas reserves based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period (the “ceiling”) is compared with the book value of the Company’s oil and gas properties at the balance sheet date. If the book value of the oil and gas properties exceeds the ceiling, a non-cash impairment charge must be recorded to reduce the book value of the oil and gas properties to the calculated ceiling. At June 30, 2013, the ceiling exceeded the book value of the oil and gas properties by approximately $199.1 million. The 12-month average of the first day of the month price for crude oil for each month during the twelve months ended June 30, 2013, based on posted Midway Sunset prices, was $100.53 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during the twelve months ended June 30, 2013, based on the quoted Henry Hub spot price for natural gas, was $3.43 per MMBtu. (Note – Because actual pricing of the Company's various producing properties varies depending on their location and hedging, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Midway Sunset and Henry Hub prices, which are only indicative of 12-month average prices for the twelve months ended June 30, 2013.) If natural gas average prices used in the ceiling test calculation at June 30, 2013 had been $1 per MMBtu lower, the book value of the Company's oil and gas properties would have exceeded the ceiling by approximately $56.6 million, which would have resulted in an impairment charge. If crude oil average prices used in the ceiling test calculation at June 30, 2013 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $157.4 million. If both natural gas and crude oil average prices used in the ceiling test calculation at June 30, 2013 were lower by $1 per MMBtu and $5 per Bbl, respectively, the book value of the Company's oil and gas properties would have exceeded the ceiling by approximately $98.5 million, which would have resulted in an impairment charge. These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation. For a more complete discussion of the full cost method of accounting, refer to "Oil and Gas Exploration and Development Costs" under "Critical Accounting Estimates" in Item 7 of the Company's 2012 Form 10-K.

RESULTS OF OPERATIONS

Earnings

The Company's earnings were $58.5 million for the quarter ended June 30, 2013 compared with earnings of $43.2 million for the quarter ended June 30, 2012. The increase in earnings of $15.3 million is primarily a result of higher earnings in all of the Company's segments as well as in the All Other category.

The Company's earnings were $212.2 million for the nine months ended June 30, 2013 compared to earnings of $171.3 million for the nine months ended June 30, 2012. The increase in earnings of $40.9 million is primarily a result of higher earnings in all of the Company's segments as well as in the All Other category.

Additional discussion of earnings in each of the business segments can be found in the business segment information that follows. Note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted.

Earnings (Loss) by Segment

	Three Months Ended June 30,			Nine Months Ended June 30,		
			Increase			Increase
(Thousands)	2013	2012	(Decrease)	2013	2012	(Decrease)
Utility	$ 7,630	$ 5,096	$ 2,534	$ 65,024	$ 52,725	$ 12,299
Pipeline and Storage	14,075	12,627	1,448	47,803	35,428	12,375
Exploration and Production	31,734	21,915	9,819	86,125	74,422	11,703
Energy Marketing	963	923	40	5,741	4,662	1,079
Total Reportable Segments	54,402	40,561	13,841	204,693	167,237	37,456
All Other	4,499	2,815	1,684	9,449	5,557	3,892
Corporate	(406)	(192)	(214)	(1,983)	(1,519)	(464)
Total Consolidated	$ 58,495	$ 43,184	$ 15,311	$ 212,159	$ 171,275	$ 40,884

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Utility

Utility Operating Revenues

(Thousands)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Increase (Decrease)	Nine Months Ended June 30, 2013	Nine Months Ended June 30, 2012	Increase (Decrease)
Retail Sales Revenues:						
Residential	$ 101,903	$ 82,738	$ 19,165	$ 456,409	$ 438,409	$ 18,000
Commercial	11,827	9,262	2,565	60,179	55,115	5,064
Industrial	951	1,005	(54)	5,178	3,703	1,475
	114,681	93,005	21,676	521,766	497,227	24,539
Transportation	28,261	24,850	3,411	114,974	102,938	12,036
Off-System Sales	-	-	-	25,020	27,010	(1,990)
Other	1,620	2,088	(468)	5,463	8,304	(2,841)
	$ 144,562	$ 119,943	$ 24,619	$ 667,223	$ 635,479	$ 31,744

Utility Throughput

(MMcf)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Increase (Decrease)	Nine Months Ended June 30, 2013	Nine Months Ended June 30, 2012	Increase (Decrease)
Retail Sales:						
Residential	8,600	7,543	1,057	49,124	43,476	5,648
Commercial	1,187	954	233	7,025	6,109	916
Industrial	113	168	(55)	820	456	364
	9,900	8,665	1,235	56,969	50,041	6,928
Transportation	13,282	12,016	1,266	59,536	51,663	7,873
Off-System Sales	-	-	-	6,716	9,544	(2,828)
	23,182	20,681	2,501	123,221	111,248	11,973

Degree Days

Three Months Ended June 30	Normal	2013	2012	Percent Colder (Warmer) Than Normal[1]	Prior Year[1]
Buffalo	912	790	751	(13.4)	5.2
Erie	871	791	751	(9.2)	5.3
Nine Months Ended June 30					
Buffalo	6,455	5,971	5,171	(7.5)	15.5
Erie	6,023	5,756	4,875	(4.4)	18.1

(1) Percents compare actual 2013 degree days to normal degree days and actual 2013 degree days to actual 2012 degree days.

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2013 Compared with 2012

Operating revenues for the Utility segment increased $24.6 million for the quarter ended June 30, 2013 as compared with the quarter ended June 30, 2012. This increase resulted from a $21.7 million increase in retail gas sales revenues and a $3.4 million increase in transportation revenues. The increase in retail gas sales revenues was primarily due to the impact of a 1.2 Bcf increase in retail throughput and the impact of a higher cost of purchased gas sold. The increase in retail throughput was largely the result of colder weather compared to the prior period. The Utility segment's average cost of purchased gas sold increased 34% quarter over quarter. The increase in transportation revenues of $3.4 million was primarily due to a 1.3 Bcf increase in transportation throughput, largely the result of colder weather compared to the prior period and the migration of customers from retail sales to transportation services.

Operating revenues for the Utility segment increased $31.7 million for the nine months ended June 30, 2013 as compared with the nine months ended June 30, 2012. This increase resulted from a $24.5 million increase in retail gas sales revenues and a $12.0 million increase in transportation revenues. These were partially offset by a $2.0 million decrease in off-system sales revenue (due to lower volumes), and a $2.8 million decrease in other revenue. The increase in transportation revenues of $12.0 million was primarily due to a 7.9 Bcf increase in transportation throughput, largely the result of colder weather compared to the prior period and the migration of customers from retail sales to transportation services. The increase in retail gas sales revenues was primarily due to the impact of a 6.9 Bcf increase in retail throughput as the cost of purchased gas sold was relatively flat period over period. The increase in retail throughput was largely the result of colder weather compared to the prior period. The decrease in other revenue was largely due to the non-recurrence of a regulatory adjustment recorded during the quarter ended March 31, 2012 to increase previous undercollection of pension and other post-retirement benefit costs. In addition, a decline in capacity release revenues led to a decline in other revenues. As a result of the unusually warm winter during fiscal 2012, the demand for capacity release volumes decreased as contracts for Distribution Corporation's fiscal 2013 capacity were being executed, which led to a decrease in the capacity release rates and revenues. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there is not a material impact to margins.

The Utility segment's earnings for the quarter ended June 30, 2013 were $7.6 million, an increase of $2.5 million when compared with earnings of $5.1 million for the quarter ended June 30, 2012. The increase in earnings is largely attributable to higher usage per account ($1.0 million) and colder weather ($0.4 million). The phrase "usage per account" refers to average gas consumption per account after factoring out any impact that weather may have had on consumption. In addition, lower interest expense of $0.6 million further increased earnings. The decrease in interest expense was attributable to a decrease in the weighted average amount of debt outstanding (due to the Utility segment's share ($90 million) of the $250 million of 5.25% notes that matured in March 2013).

The impact of weather variations on earnings in the Utility segment's New York rate jurisdiction is mitigated by that jurisdiction's weather normalization clause (WNC). The WNC in New York, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the Utility segment's New York customers. For the quarter ended June 30, 2013, the WNC preserved earnings of approximately $0.4 million, as the weather was warmer than normal. For the quarter ended June 30, 2012, the WNC preserved earnings of approximately $1.2 million, as the weather was warmer than normal.

The Utility segment's earnings for the nine months ended June 30, 2013 were $65.0 million, an increase of $12.3 million when compared with earnings of $52.7 million for the nine months ended June 30, 2012. The increase in earnings is largely attributable to colder weather ($6.8 million) and higher usage per account ($0.5 million). In addition, lower income tax expense of $2.0 million (primarily as a result of a favorable tax settlement), lower operating expenses of $1.4 million (due to decreased bad debt expense) and lower interest expense of $1.4 million (primarily a result of a reduced debt balance as discussed above and interest adjustments related to a favorable tax settlement) led to further increases in earnings.

For the nine months ended June 30, 2013, the WNC preserved earnings of approximately $2.1 million, as the weather was warmer than normal. For the nine months ended June 30, 2012, the WNC preserved earnings of approximately $5.9 million, as the weather was warmer than normal.

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Pipeline and Storage

Pipeline and Storage Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2013	2012	Increase (Decrease)	2013	2012	Increase (Decrease)
Firm Transportation	$ 45,809	$ 40,065	$ 5,744	$ 143,041	$ 124,204	$ 18,837
Interruptible Transportation	533	318	215	1,548	1,056	492
	46,342	40,383	5,959	144,589	125,260	19,329
Firm Storage Service	17,405	17,226	179	53,067	50,408	2,659
Interruptible Storage Service	1	7	(6)	1	7	(6)
Other	1,015	1,091	(76)	3,456	2,735	721
	$ 64,763	$ 58,707	$ 6,056	$ 201,113	$ 178,410	$ 22,703

Pipeline and Storage Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2013	2012	Increase	2013	2012	Increase
Firm Transportation	129,021	79,921	49,100	427,209	281,579	145,630
Interruptible Transportation	540	247	293	2,506	1,511	995
	129,561	80,168	49,393	429,715	283,090	146,625

2013 Compared with 2012

Operating revenues for the Pipeline and Storage segment increased $6.1 million for the quarter ended June 30, 2013 as compared with the quarter ended June 30, 2012. The increase was primarily due to an increase in transportation revenues of $6.0 million. The increase in transportation revenues was largely due to demand charges on new contracts for transportation service on Supply Corporation's Line N 2012 Expansion Project, which was placed fully in service in November 2012, and Supply Corporation's Northern Access expansion project, which was placed fully in service in January 2013. These projects provide pipeline capacity for Marcellus Shale production. The Line N 2012 Expansion Project and the Northern Access expansion project are discussed in the Investing Cash Flow section that follows. Additionally, effective May 2012, both transportation and storage revenues increased due to an overall net increase in tariff rates as a result of the implementation of Supply Corporation's rate case settlement which was approved by FERC on August 6, 2012.

Operating revenues for the Pipeline and Storage segment for the nine months ended June 30, 2013 increased $22.7 million as compared with the nine months ended June 30, 2012. The increase was primarily due to an increase in transportation revenues of $19.3 million and an increase in storage revenues of $2.7 million. The increase in transportation revenues was largely due to demand charges on new contracts for transportation service on Supply Corporation's Line N 2012 Expansion Project and Supply Corporation's Northern Access expansion project, as discussed above, and Empire's Tioga County Extension Project, which was placed in service in November 2011. Transportation and storage revenues also increased due to an overall net increase in tariff rates as a result of the implementation of Supply Corporation's rate case settlement, as noted above.

Transportation volume for the quarter ended June 30, 2013 increased by 49.4 Bcf from the prior year's quarter.   For the nine months ended June 30, 2013, transportation volume increased by 146.6 Bcf from the prior year's nine-month period. The large increase in transportation volume for the quarter and the nine-month period primarily reflects the impact of the above mentioned expansion projects being placed in service. Volume fluctuations generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

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The Pipeline and Storage segment's earnings for the quarter ended June 30, 2013 were $14.1 million, an increase of $1.5 million when compared with earnings of $12.6 million for the quarter ended June 30, 2012. The increase in earnings is primarily due to the earnings impact of higher transportation and storage revenues of $4.0 million, as discussed above, combined with a decrease in depreciation expense ($0.5 million). The decrease in depreciation expense primarily reflects a decrease in depreciation rates as specified in Supply Corporation's rate case settlement offset partly by incremental depreciation expense related to the projects that were placed in service within the last year. These earnings increases were partially offset by higher operating expenses ($1.2 million), a decrease in the allowance for funds used during construction (equity component) of $0.6 million and higher income taxes ($1.3 million). The increase in operating expenses can be attributed primarily to higher pension expense, a non-recurring gain on disposal of property, plant and equipment recorded in the prior-year quarter and an increase in the reserve for preliminary project costs. The decrease in the allowance for funds used during construction is mainly due to Supply Corporation's Line N 2012 Expansion Project and Supply Corporation's Northern Access expansion project, which were under construction in the prior year and have since been placed in service. The increase in income taxes is a result of higher state taxes and a favorable federal return to provision adjustment in 2012 that did not recur in the current year.

The Pipeline and Storage segment's earnings for the nine months ended June 30, 2013 were $47.8 million, an increase of $12.4 million when compared with earnings of $35.4 million for the nine months ended June 30, 2012. The increase in earnings is primarily due to the earnings impact of higher transportation and storage revenues of $14.3 million, as discussed above, combined with a decrease in depreciation expense ($2.2 million). The decrease in depreciation expense primarily reflects a decrease in depreciation rates as specified in Supply Corporation's rate case settlement offset partly by incremental depreciation expense related to the projects that were placed in service within the last year. These earnings increases were partially offset by higher operating expenses ($1.0 million), a decrease in the allowance for funds used during construction (equity component) of $0.5 million and higher income taxes ($2.3 million). The increase in operating expenses can be attributed primarily to higher pension expense and an increase in compressor station costs, offset partly by lower post-retirement benefit costs. The decrease in the allowance for funds used during construction is mainly due to Empire's Tioga County Expansion Project, which remained under construction during a portion of the first quarter of fiscal 2012 before being placed in service in November 2011. The increase in income taxes is a result of higher state taxes and a favorable federal return to provision adjustment in 2012 that did not recur in the current year.

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2013	2012	Increase (Decrease)	2013	2012	Increase (Decrease)
Gas (after Hedging)	$ 124,162	$ 72,456	$ 51,706	$ 309,059	$ 209,405	$ 99,654
Oil (after Hedging)	69,408	64,664	4,744	206,903	198,056	8,847
Gas Processing Plant	1,252	1,479	(227)	3,380	3,880	(500)
Other	391	(50)	441	(600)	108	(708)
	$ 195,213	$ 138,549	$ 56,664	$ 518,742	$ 411,449	$ 107,293

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Production Volumes

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2013	2012	Increase (Decrease)	2013	2012	Increase (Decrease)
Gas Production (MMcf)						
Appalachia	29,038	16,778	12,260	72,518	43,125	29,393
West Coast	780	1,025	(245)	2,240	2,670	(430)
Total Production	29,818	17,803	12,015	74,758	45,795	28,963
Oil Production (Mbbl)						
Appalachia	9	11	(2)	21	29	(8)
West Coast	700	710	(10)	2,093	2,136	(43)
Total Production	709	721	(12)	2,114	2,165	(51)

Average Prices

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2013	2012	Increase (Decrease)	2013	2012	Increase (Decrease)
Average Gas Price/Mcf						
Appalachia	$ 3.97	$ 2.14	$ 1.83	$ 3.58	$ 2.70	$ 0.88
West Coast [(1)]	$ 6.73	$ 5.42	$ 1.31	$ 6.50	$ 6.64	$ (0.14)
Weighted Average	$ 4.04	$ 2.33	$ 1.71	$ 3.67	$ 2.93	$ 0.74
Weighted Average After Hedging	$ 4.16	$ 4.07	$ 0.09	$ 4.13	$ 4.57	$ (0.44)
Average Oil Price/Bbl						
Appalachia	$ 95.06	$ 95.43	$ (0.37)	$ 93.18	$ 94.24	$ (1.06)
West Coast	$ 101.05	$ 104.24	$ (3.19)	$ 102.44	$ 108.56	$ (6.12)
Weighted Average	$ 100.98	$ 104.11	$ (3.13)	$ 102.35	$ 108.37	$ (6.02)
Weighted Average After Hedging	$ 97.90	$ 89.70	$ 8.20	$ 97.88	$ 91.50	$ 6.38

(1) Prices for all periods presented reflect revenues from gas produced on the West Coast, including natural gas liquids. In previous quarters, natural gas liquids were reported as gas processing plant revenues as opposed to natural gas revenues.

2013 Compared with 2012

Operating revenues for the Exploration and Production segment increased $56.7 million for the quarter ended June 30, 2013 as compared with the quarter ended June 30, 2012. Gas production revenue after hedging increased $51.7 million, due to an increase in production coupled with a $0.09 per Mcf increase in the weighted average price of natural gas after hedging. The increase in Appalachian production was primarily due to increased development within the Marcellus Shale formation, mainly in Lycoming County, Pennsylvania. Oil production revenue after hedging increased $4.7 million, due to an $8.20 per Bbl increase in the weighted average price of crude oil after hedging as production was slightly lower quarter over quarter.

Operating revenues for the Exploration and Production segment increased $107.3 million for the nine months ended June 30, 2013 as compared with the nine months ended June 30, 2012. Gas production revenue after hedging increased $99.7 million, due to an increase in production which was partially offset by a $0.44 per Mcf decrease in the weighted average price of natural gas after hedging. The increase in Appalachian production was primarily due to increased development within the Marcellus Shale formation, mainly in Lycoming County, Pennsylvania with additional Marcellus Shale production from Tioga County, Pennsylvania. Oil production revenue after hedging increased $8.8

million due to a $6.38 per Bbl increase in the weighted average price of crude oil after hedging. Oil production was slightly lower period over period. Partially offsetting these revenue increases, other revenues decreased $0.7 million (largely due to a royalty adjustment) and processing plant revenues decreased $0.5 million (largely due to East Coast pricing and volume fluctuations and a temporary shutdown of its plant during December 2012).

The Exploration and Production segment's earnings for the quarter ended June 30, 2013 were $31.7 million, an increase of $9.8 million when compared with earnings of $21.9 million for the quarter ended June 30, 2012. Higher natural gas production, higher realized natural gas prices (after hedging) and higher realized crude oil prices (after hedging) increased earnings by $31.8 million, $1.8 million and $3.8 million, respectively. These items were partially offset by higher depletion expense ($9.6 million), higher production costs ($8.8 million), higher income taxes ($5.1 million), higher general, administrative and other operating expenses ($2.0 million), higher interest expense ($1.3 million), and lower crude oil production ($0.7 million). The increase in depletion expense is primarily due to an increase in the depletable base (due to increased capital spending in the Appalachian region within the last few years) and higher production. The increase in production costs is largely attributable to higher transportation costs. In addition, compression and water disposal costs in the Appalachian region coupled with higher well repair, maintenance, and labor costs in the West Coast region led to further increases in production costs. As a result of the increasing Appalachian production in Pennsylvania, the Company reevaluated its deferred taxes for state income tax purposes during the quarter ended June 30, 2013. Since a greater percentage of the Exploration and Production segment’s earnings were coming from Pennsylvania than was originally anticipated, this caused the Company to use a higher state income tax rate in valuing its deferred state income tax liability, which led to a $5.0 million adjustment (net) to increase that liability as of June 30, 2013 and a corresponding increase to income tax expense. The increase in general, administrative and other operating expenses was largely due to an increase in personnel costs. The increase in interest expense was attributable to an increase in the weighted average amount of debt (due to the Exploration and Production segment’s share ($350 million) of the $500 million long-term debt issuance (at 3.75%) in February 2013).

The Exploration and Production segment's earnings for the nine months ended June 30, 2013 were $86.1 million, an increase of $11.7 million when compared with earnings of $74.4 million for the nine months ended June 30, 2012. Higher natural gas production and higher realized crude oil prices (after hedging) increased earnings by $86.1 million and $8.8 million, respectively. In addition, there was a $4.6 million decrease in property and other taxes, which largely reflects the accrual of a $4.0 million natural gas impact fee related to Marcellus Shale wells drilled prior to fiscal 2012. This fee was first imposed by Pennsylvania during the quarter ended March 31, 2012. As the impact fee accrued during the nine months ended June 30, 2013 was attributable only to current activity, there was a decrease in property and other taxes. These items were partially offset by lower natural gas prices after hedging ($21.3 million), higher depletion expense ($27.3 million), higher production costs ($17.8 million), higher general, administrative and other operating expenses ($6.8 million), higher interest expense ($5.4 million), higher income taxes ($5.4 million), lower crude oil production ($3.0 million), and lower other income and processing plant revenues ($0.8 million). The increase in depletion expense is primarily due to an increase in the depletable base (due to increased capital spending in the Appalachian region within the last few years) and higher production. The increase in production costs is largely attributable to higher transportation costs. In addition, compression and water disposal costs in the Appalachian region coupled with higher well repair, maintenance, and labor costs in the West Coast region led to further increases in production costs. The increase in general, administrative and other operating expenses was largely due to an increase in personnel costs. The increase in interest expense was attributable to an increase in the weighted average amount of debt (due to the Exploration and Production segment’s share ($350 million) of the $500 million long-term debt issuance (at 3.75%) in February 2013 and ($470 million) of a $500 million long-term debt issuance (at 4.90%) in December 2011. The increase in income taxes is largely due to higher deferred state income taxes, as discussed above.

Energy Marketing

Energy Marketing Operating Revenues

(Thousands)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Increase	Nine Months Ended June 30, 2013	Nine Months Ended June 30, 2012	Increase (Decrease)
Natural Gas (after Hedging)	$ 59,565	$ 35,950	$ 23,615	$ 183,330	$ 162,923	$ 20,407
Other	9	6	3	32	34	(2)
	$ 59,574	$ 35,956	$ 23,618	$ 183,362	$ 162,957	$ 20,405

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Energy Marketing Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2013	2012	Increase	2013	2012	Increase
Natural Gas – (MMcf)	12,508	10,818	1,690	40,266	38,857	1,409

2013 Compared with 2012

Operating revenues for the Energy Marketing segment increased $23.6 million for the quarter ended June 30, 2013 as compared with the quarter June 30, 2012. Operating revenues for the Energy Marketing segment increased $20.4 million for the nine months ended June 30, 2013 as compared with the nine months ended June 30, 2012. The increase for both the quarter and nine months ended June 30, 2013 reflects an increase in gas sales revenue due to a higher average price of natural gas as well as an increase in volume sold due to colder weather.

The Energy Marketing segment's earnings for the quarter ended June 30, 2013 were $1.0 million, an increase of less than $0.1 million when compared with the earnings for the quarter ended June 30, 2012. The Energy Marketing segment's earnings for the nine months ended June 30, 2013 were $5.7 million, an increase of $1.0 million when compared with earnings of $4.7 million for the nine months ended June 30, 2012. The increase in earnings for the nine months ended June 30, 2013 was largely attributable to higher margin of $0.9 million and lower operating costs of $0.3 million. The increase in margin was primarily driven by an increase in the benefit the Energy Marketing segment derived from its contracts for storage capacity. The decrease in operating costs reflects a reduction in expenses for computer software, professional services and advertising.

Corporate and All Other

2013 Compared with 2012

Corporate and All Other operations recorded earnings of $4.1 million for the quarter ended June 30, 2013, an increase of $1.5 million when compared with earnings of $2.6 million for the quarter ended June 30, 2012. The increase in earnings was primarily due to higher gathering and processing revenues of $4.0 million (due to Midstream Corporation's Trout Run Gathering System being placed in service in May 2012 and the expansion of Midstream

Corporation's Covington Gathering System). This was partially offset by higher operating costs of $1.3 million, higher income tax expense of $0.9 million and higher depreciation expense of $0.3 million. The expansion discussed above was primarily responsible for the increase in operating costs and depreciation expense. The increase in income tax expense was largely due to higher state taxes.

For the nine months ended June 30, 2013, Corporate and All Other operations had earnings of $7.5 million, an increase of $3.5 million when compared with earnings of $4.0 million for the nine months ended June 30, 2012. The increase in earnings was primarily due to higher gathering and processing revenues of $8.5 million (due to Midstream Corporation's Trout Run Gathering System being placed in service in May 2012 and the expansion of Midstream Corporation's Covington Gathering System). This was partially offset by higher operating costs of $1.7 million, higher depreciation expense of $1.6 million and higher income tax expense of $1.2 million. The expansion discussed above was primarily responsible for the increase in operating costs and depreciation expense. The increase in income tax expense was largely due to higher state taxes.

Interest Expense on Long-Term Debt (amounts below are pre-tax amounts)

Interest on long-term debt increased $1.5 million for the quarter ended June 30, 2013 as compared with the quarter ended June 30, 2012. For the nine months ended June 30, 2013, interest on long-term debt increased $6.6 million as compared with the nine months ended June 30, 2012. This increase is due to a higher average amount of long-term debt outstanding partially offset by a decrease in the weighted average interest rate on such debt. The Company issued $500 million of 3.75% notes in February 2013 and repaid $250 million of 5.25% notes that matured in March 2013. In addition, the Company issued $500 million of 4.90% notes in December 2011 and repaid $150 million of 6.70% notes that matured in November 2011.

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CAPITAL RESOURCES AND LIQUIDITY

The Company's primary sources of cash during the nine-month period ended June 30, 2013 consisted of cash provided by operating activities and proceeds from the issuance of long-term debt. The Company's primary sources of cash during the nine-month period ended June 30, 2012 consisted of cash provided by operating activities, proceeds from the issuance of long-term debt and net proceeds from short-term borrowings. These sources of cash were supplemented by net proceeds from the issuance of common stock for both the nine months ended June 30, 2013 and June 30, 2012, including the issuance of original issue shares for the Direct Stock Purchase and Dividend Reinvestment Plan. During the nine months ended June 30, 2013 and June 30, 2012, the common stock used to fulfill the requirements of the Company's 401(k) plans was obtained via open market purchases.

Operating Cash Flow

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization and deferred income taxes.

Cash provided by operating activities in the Utility and Pipeline and Storage segments may vary substantially from period to period because of the impact of rate cases. In the Utility segment, supplier refunds, over- or under-recovered purchased gas costs and weather may also significantly impact cash flow. The impact of weather on cash flow is tempered in the Utility segment's New York rate jurisdiction by its WNC and in the Pipeline and Storage segment by the straight fixed-variable rate design used by Supply Corporation and Empire.

Because of the seasonal nature of the heating business in the Utility and Energy Marketing segments, revenues in these segments are relatively high during the heating season, primarily the first and second quarters of the fiscal year, and receivable balances historically increase during these periods from the receivable balances at September 30.

The storage gas inventory normally declines during the first and second quarters of the fiscal year and is replenished during the third and fourth quarters. For storage gas inventory accounted for under the LIFO method, the current cost of replacing gas withdrawn from storage is recorded in the Consolidated Statements of Income and a reserve for gas replacement is recorded in the Consolidated Balance Sheets under the caption "Other Accruals and Current Liabilities." Such reserve is reduced as the inventory is replenished.

Cash provided by operating activities in the Exploration and Production segment may vary from period to period as a result of changes in the commodity prices of natural gas and crude oil as well as changes in production. The

Company uses various derivative financial instruments, including price swap agreements and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $587.2 million for the nine months ended June 30, 2013, an increase of $13.4 million compared with $573.8 million provided by operating activities for the nine months ended June 30, 2012. The increase in cash provided by operating activities reflects higher cash provided by operating activities in the Pipeline and Storage segment and Exploration and Production segment, partly offset by lower cash provided by operating activities in the Utility segment. The increase in the Pipeline and Storage segment is due to higher cash receipts from transportation revenues as a result of expansion projects coming on-line and higher tariff rates from the implementation of Supply Corporation’s rate case proceeding, as discussed above. The increase in the Exploration and Production segment is primarily due to higher cash receipts from natural gas production in the Appalachian region, partially offset by a decrease in cash provided by operations from hedging collateral account fluctuations. The decrease in the Utility segment can be attributed to the timing of receivable collections. The winter of 2012 was substantially warmer than normal, resulting in lower receivable balances at June 30, 2012 that were collected in subsequent months. The winter of 2013 has seen more normal temperatures, resulting in higher receivable balances at June 30, 2013 that will be collected in subsequent months.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company’s expenditures for long-lived assets totaled $504.5 million during the nine months ended June 30, 2013 and $803.2 million for the nine months ended June 30, 2012. These amounts include accounts payable and accrued liabilities related to capital expenditures and will differ from capital expenditures shown on the Consolidated Statement of Cash Flows. They are included in subsequent Consolidated Statement of Cash Flows when they are paid. The table below presents these expenditures:

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Total Expenditures for Long-Lived Assets

Nine Months Ended June 30, (Millions)	2013		2012		Increase (Decrease)
Utility:					
Capital Expenditures	$ 43.0	(1)	$ 39.9	(2)	$ 3.1
Pipeline and Storage:					
Capital Expenditures	41.0	(1)	97.3	(2)	(56.3)
Exploration and Production:					
Capital Expenditures	385.0	(1)	598.6	(2)	(213.6)
All Other:					
Capital Expenditures	35.5	(1)	67.4	(2)	(31.9)
	$ 504.5		$ 803.2		$ (298.7)

(1) At June 30, 2013, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Utility segment and the All Other category include $49.1 million, $6.9 million, $0.2 million and $2.4 million, respectively, of accounts payable and accrued liabilities related to capital expenditures. At September 30, 2012, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Utility segment and the All Other category included $38.9 million, $12.7 million, $3.2 million and $12.7 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

(2) At June 30, 2012, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Utility segment and the All Other category included $92.2 million, $8.6 million, $1.0 million and $16.8 million, respectively, of accounts payable and accrued liabilities related to capital expenditures. At September 30, 2011, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Utility segment and the All Other category included $103.3 million, $16.4 million, $2.3 million and $3.1 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

Utility

The majority of the Utility capital expenditures for the nine months ended June 30, 2013 and June 30, 2012 were made for replacement of mains and main extensions, as well as for the replacement of service lines.

Pipeline and Storage

The Pipeline and Storage capital expenditures for the nine months ended June 30, 2013 were mainly related to the construction of Supply Corporation's Northern Access expansion project ($16.2 million) and Supply Corporation's Line N 2012 Expansion Project ($4.3 million) as discussed below, as well as for additions, improvements and replacements to this segment's transmission and gas storage systems. The majority of the Pipeline and Storage capital expenditures for the nine months ended June 30, 2012 were related to the construction of Supply Corporation's Northern Access expansion project ($24.3 million), Empire's Tioga County Extension Project ($20.4 million), Supply Corporation's Line N 2012 Expansion Project ($18.8 million), and Supply Corporation's Line N Expansion Project ($2.5 million). The Pipeline and Storage capital expenditures for the nine months ended June 30, 2012 also include additions, improvements, and replacements to this segment's transmission and gas storage systems.

In light of the growing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia — specifically in the Marcellus and Utica Shale producing areas — Supply Corporation and Empire are actively pursuing several expansion projects and paying for preliminary survey and investigation costs, which are initially recorded as Deferred Charges on the Consolidated Balance Sheet. An offsetting reserve is established as those preliminary survey and investigation costs are incurred, which reduces the Deferred Charges balance and increases Operation and Maintenance Expense on the Consolidated Statement of Income. The Company reviews all projects on a quarterly basis, and if it is determined that it is highly probable that the project will be built, the reserve is reversed. This reversal reduces Operation and Maintenance Expense and reestablishes the original balance in Deferred Charges. After the reversal of the reserve, the amounts remain in Deferred Charges until such time as capital expenditures for the project have been incurred and activities that are necessary to get the construction project ready for its intended use are in progress. At that point, the balance is transferred from Deferred Charges to Construction Work in Progress, a component of Property, Plant and Equipment on the Consolidated Balance Sheet. As of June 30, 2013, the total amount reserved for the Pipeline and Storage segment's preliminary survey and investigation costs was $7.9 million.

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Supply Corporation and Empire have completed in fiscal 2013 or are moving forward with several projects designed to move anticipated Marcellus and Utica production gas to other interstate pipelines and to markets beyond the Supply Corporation and Empire pipeline systems. Projects where the Company has begun to make significant investments of preliminary survey and investigation costs and/or where shipper agreements have been executed are described below.

Supply Corporation has begun service under a transportation service agreement with Statoil Natural Gas LLC ("Statoil") which provides 320,000 Dth per day of firm transportation capacity for a 20-year term in conjunction with Supply Corporation's "Northern Access" expansion project. This capacity provides Statoil with a firm transportation path from the Tennessee Gas Pipeline ("TGP") 300 Line at Ellisburg and Transcontinental Pipeline at Leidy to the TransCanada Pipeline at Niagara. These receipt points are attractive because they provide routes for Marcellus shale gas from the TGP 300 Line and Transco Leidy Line in northern Pennsylvania, to be transported from the Marcellus supply basin to northern markets. Supply Corporation received from the FERC its NGA Section 7(c) Certificate authorization of this project on October 20, 2011, and received its Notice to Proceed on April 13, 2012. The project facilities involve approximately 9,500 horsepower of additional compression at Supply Corporation's existing Ellisburg Station and a new approximately 5,000 horsepower compressor station in Wales, New York, along with other system enhancements including enhancements to the jointly owned Niagara Spur Loop Line. Initial service began on November 1, 2012, with full service implemented on January 16, 2013. The completed cost for the Northern Access expansion is expected to be approximately $77.4 million. As of June 30, 2013, approximately $70.1 million has been spent on the Northern Access expansion project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2013.

Supply Corporation has also begun service under three service agreements for a total of 163,000 Dth per day of additional capacity on Line N to TETCO at Holbrook ("Line N 2012 Expansion Project"). The FERC issued the NGA Section 7(c) Certificate on March 29, 2012 authorizing construction and operation of the Line N 2012 Expansion Project, which consists of an additional 20,620 horsepower of compression at its Buffalo Compressor Station, and the replacement of 4.85 miles of 20" pipe with 24" pipe, to enhance the integrity and reliability of its system and to create the additional capacity. On October 3, 2012, Supply Corporation put in service a portion of the Project facilities and began early interim service for Range Resources. It began full service for all Project shippers on November 1, 2012. The completed cost for the Line N 2012 Expansion Project is expected to be approximately $32.3 million for the incremental capacity plus approximately $7.1 million allocated to system replacement. Of this amount, approximately $37.2 million has been spent on the Line N 2012 Expansion Project through June 30, 2013, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2013.

In 2011, Supply Corporation concluded an Open Season to increase its capability to move gas north on its Line N system and deliver gas to a new interconnection with Tennessee Gas Pipeline at Mercer, Pennsylvania, a pooling point recently established at Tennessee's Station 219 ("Mercer Expansion Project"). Supply Corporation has executed a precedent agreement for 105,000 Dth per day, all of the project capacity, for service expected to begin November 2014. The preliminary cost estimate is $29 million, of which $25.7 million is for expansion and $3.3 million is for system modernization. Supply Corporation expects to construct the required approximately 3,500 horsepower of compression at Mercer, and replace 2.19 miles of pipeline, all under its FERC blanket certificate authorization. No significant amounts have been spent on this project through June 30, 2013.

On April 11, 2012, Supply Corporation concluded an Open Season to increase its capacity to move gas south on its Line N system to TETCO at Holbrook ("Line N 2013 Project"). Supply Corporation has executed a precedent agreement for 30,000 Dth per day, all of the project capacity, for service expected to begin November 2013. The preliminary cost estimate is $4.4 million. Supply Corporation expects to replace 1.27 miles of 20" pipeline with 24" pipeline under its FERC blanket certificate authorization. No significant amounts have been spent on this project through June 30, 2013.

On January 18, 2013, Supply Corporation concluded an Open Season to further increase its capacity to move gas north and south on its Line N system to TETCO at Holbrook and TGP at Mercer ("Westside Expansion and Modernization Project"). Supply Corporation received requests during the Open Season for 95,000 Dth per day of the project capacity, for service expected to begin in 2015. Precedent agreements have been extended to these prospective shippers and discussions are underway with other parties interested in additional Line N capacity. The Westside Expansion and Modernization Project facilities are expected to include the replacement of approximately 23 miles of 20" pipe with 24" pipe and the addition of approximately 1,750 horsepower of compression at Mercer. The preliminary cost estimate is $66 million, of which $31 million is related to expansion and the remainder is for replacement. No significant amounts have been spent on this project through June 30, 2013.

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On April 12, 2013, Supply Corporation concluded an Open Season to increase its capacity to move gas south on its Line N system by an expansion of the interconnection facilities to TETCO at Holbrook ("Holbrook Expansion Project"). Supply Corporation received requests for approximately 13,000 Dth per day of capacity, for service expected to begin November 2013. The preliminary cost estimate is $0.75 million. No significant amounts have been spent on this project through June 30, 2013.

On December 17, 2010, Empire concluded an Open Season for up to 260,000 Dth per day of additional capacity from Tioga County, Pennsylvania, to TransCanada Pipeline and the TGP 200 Line, as well as additional short-haul capacity to Millennium Pipeline at Corning ("Central Tioga County Extension"). Empire is in discussions with an anchor shipper for a significant portion of the proposed capacity, with service commencing in 2015 or later, likely depending on a rebound in commodity pricing due to the dry gas nature of this area of the Marcellus. The Central Tioga County Extension project may involve up to 25,000 horsepower of compression at up to three new stations and a 25 mile 24" pipeline extension, at a preliminary cost estimate of $150 million. No significant amounts have been spent on this project through June 30, 2013.

Exploration and Production

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2013 were primarily well drilling and completion expenditures and included approximately $312.4 million for the Appalachian region (including $290.1 million in the Marcellus Shale area) and $72.6 million for the West Coast region. These amounts included approximately $115.1 million spent to develop proved undeveloped reserves.

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2012 were primarily well drilling and completion expenditures and included approximately $552.0 million for the Appalachian region (including $500.4 million in the Marcellus Shale area) and $46.6 million for the West Coast region. These amounts included approximately $198.7 million spent to develop proved undeveloped reserves.

All Other

The majority of the All Other category's capital expenditures for the nine months ended June 30, 2013 were for the expansion of Midstream Corporation's Trout Run Gathering System, as discussed below. The majority of the All Other category's capital expenditures for the nine months ended June 30, 2012 were for the construction of Midstream Corporation's Trout Run Gathering System and the expansion of Midstream Corporation's Covington Gathering system, as discussed below.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, is developing a gathering system in Lycoming County, Pennsylvania. The project, Trout Run Gathering System, was placed in service in May 2012. The current system consists of approximately 40 miles of backbone and in-field gathering system. The complete buildout will include in-field gathering pipelines and compression at a total cost of approximately $185 million. As of June 30, 2013, the Company has spent approximately $112.5 million in costs related to this project, including approximately $32.4 million spent during the nine months ended June 30, 2013, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2013.

NFG Midstream Covington, LLC, a wholly owned subsidiary of Midstream Corporation, has been expanding its gathering system in Tioga County, Pennsylvania. As of June 30, 2013, the Company has spent approximately $27.8 million in costs related to the Covington Gathering System. All costs associated with this gathering system are included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2013.

In addition, two other wholly owned subsidiaries of Midstream Corporation, NFG Midstream Mt. Jewett, LLC and NFG Midstream Tionesta, LLC are constructing gathering pipelines and interconnects. As of June 30, 2013, approximately $3.4 million has been spent on the NFG Midstream Mt. Jewett gathering system and approximately $2.1 million has been spent on the NFG Midstream Tionesta gathering system, all of which has been capitalized as Construction Work in Progress.

Midstream Corporation is planning the construction of several other gathering systems. As of June 30, 2013, the Company has spent approximately $0.7 million in costs related to these projects, all of which has been capitalized as Construction Work in Progress.

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Project Funding

The Company has been financing the Pipeline and Storage segment projects and the Midstream Corporation projects mentioned above, as well as the Exploration and Production segment capital expenditures, with cash from operations and both short and long-term borrowings. The Company issued additional long-term debt in February 2013 to enhance its liquidity position. Going forward, while the Company expects to use cash from operations as the first means of financing these projects, it is expected that the Company will continue to use short-term borrowings if necessary during fiscal 2013. The level of such short-term borrowings will depend upon the amounts of cash provided by operations, which, in turn, will likely be impacted by natural gas and crude oil prices combined with production from existing wells.

The Company continuously evaluates capital expenditures and potential investments in corporations, partnerships, and other business entities. The amounts are subject to modification for opportunities such as the acquisition of attractive oil and gas properties, natural gas storage facilities and the expansion of natural gas transmission line capacities. While the majority of capital expenditures in the Utility segment are necessitated by the continued need for replacement and upgrading of mains and service lines, the magnitude of future capital expenditures or other investments in the Company’s other business segments depends, to a large degree, upon market conditions.

Financing Cash Flow

Consolidated short-term debt decreased $171.0 million when comparing the balance sheet at June 30, 2013 to the balance sheet at September 30, 2012. The maximum amount of short-term debt outstanding during the nine months ended June 30, 2013 was $272.8 million. The Company used its $500.0 million long-term debt issuance in February 2013 to substantially reduce its short-term debt. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, repurchases of stock, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. At June 30, 2013, the Company had no outstanding commercial paper or short-term notes payable to banks.

As for bank loans, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which totaled $335.0 million at June 30, 2013, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed at amounts near current levels, or substantially replaced by similar lines.

The total amount available to be issued under the Company's commercial paper program is $300.0 million. At June 30, 2013, the commercial paper program was backed by a syndicated committed credit facility totaling $750.0 million, which commitment extends through January 6, 2017. Under the committed credit facility, the Company agreed that its debt to capitalization ratio would not exceed .65 at the last day of any fiscal quarter through January 6, 2017. At June 30, 2013, the Company's debt to capitalization ratio (as calculated under the facility) was .44. The constraints specified in the committed credit facility would have permitted an additional $2.32 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

If a downgrade in any of the Company's credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its committed credit facility, uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

Under the Company's existing indenture covenants, at June 30, 2013, the Company would have been permitted to issue up to a maximum of $1.52 billion in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands. However, if the Company were to experience a significant loss in the future (for example, as a result of an impairment of oil and gas properties), it is possible, depending on factors including the magnitude of the loss, that these indenture covenants would restrict the Company's ability to issue additional long-term unsecured indebtedness for a period of up to nine calendar months, beginning with the fourth calendar month following the loss. This would not at any time preclude the Company from issuing new indebtedness to replace maturing debt.

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The Company's 1974 indenture pursuant to which $99.0 million (or 6.0%) of the Company's long-term debt (as of June 30, 2013) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement, or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company's $750.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more, or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of June 30, 2013, the Company did not have any debt outstanding under the committed credit facility.

The Company's embedded cost of long-term debt was 5.58% at June 30, 2013 and 6.17% at June 30, 2012.

The Company repaid $250.0 million of 5.25% notes that matured in March 2013, which had been classified as Current Portion of Long-Term Debt at September 30, 2012. None of the Company's long-term debt at June 30, 2013 will mature within the following twelve-month period.

On February 15, 2013, the Company issued $500.0 million of 3.75% notes due March 1, 2023. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $495.4 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used to refund the $250.0 million of 5.25% notes that matured in March 2013, as well as for general corporate purposes, including the reduction of short-term debt.

On December 1, 2011, the Company issued $500.0 million of 4.90% notes due December 1, 2021. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $496.1 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including refinancing short-term debt that was used to pay the $150 million due at the maturity of the Company's 6.70% notes in November 2011.

The Company may issue debt or equity securities in a public offering or a private placement from time to time. The amounts and timing of the issuance and sale of debt or equity securities will depend on market conditions, indenture requirements, regulatory authorizations and the capital requirements of the Company.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating leases. The Company’s consolidated subsidiaries have operating leases, the majority of which are with the Exploration and Production segment and Corporate operations, having a remaining lease commitment of approximately $63.2 million. These leases have been entered into for the use of compressors, drilling rigs, buildings, meters and other items and are accounted for as operating leases.

OTHER MATTERS

In addition to the legal proceedings disclosed in Part II, Item 1 of this report, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the quarterly and annual period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

During the nine months ended June 30, 2013, the Company contributed $42.0 million to its Retirement Plan and $15.8 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2013, the Company expects to contribute approximately $10.0 million to its Retirement Plan. Changes in the discount rate, other actuarial assumptions, and asset performance could ultimately cause the Company to fund larger amounts to the Retirement Plan in fiscal 2013 in order to be in compliance with the Pension Protection Act of 2006. In July 2012, the Surface Transportation Extension Act, which is also referred to as the Moving Ahead for Progress in the 21st Century Act (the Act), was passed by Congress and signed by the President. The Act included pension funding stabilization provisions. The Company is continually evaluating its future contributions in light of the provisions of the Act. In the remainder of 2013, the Company expects to contribute approximately $2.2 million to its VEBA trusts and 401(h) accounts.

Market Risk Sensitive Instruments

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives have or will become effective as federal agencies (including the CFTC, various banking regulators and the SEC) adopt rules to implement the law. For purposes of the Dodd-Frank Act, under rules adopted by the SEC and/or CFTC, the Company believes that it qualifies as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge or mitigate commercial risk. Nevertheless, other rules that are being developed could have a significant impact on the Company. For example, banking regulators have proposed a rule that would require swap dealers and major swap participants subject to their jurisdiction to collect initial and variation margin from counterparties that are non-financial end users, though such swap dealers and major swap participants would have the discretion to set thresholds for posting margin (unsecured credit limits). Regardless of the levels of margin that might be required, concern remains that swap dealers and major swap participants will pass along their increased capital and margin costs through higher prices and reductions in thresholds for posting margin. In addition, while the Company expects to be exempt from the Dodd-Frank Act’s requirement that swaps be cleared and traded on exchanges or swap execution facilities, the cost of entering into a non-exchange cleared swap that is available as an exchange cleared swap may be greater. The Company continues to monitor these developments but cannot predict the impact the Dodd-Frank Act may ultimately have on its operations.

In accordance with the authoritative guidance for fair value measurements, the Company has identified certain inputs used to recognize fair value as Level 3 (unobservable inputs). The Level 3 derivative net liabilities relate to crude oil swap agreements used to hedge forecasted sales at a specific location (southern California). The Company’s internal model that is used to calculate fair value applies a historical basis differential (between the sales locations and NYMEX) to a forward NYMEX curve because there is not a forward curve specific to this sales location. Given the high level of historical correlation between NYMEX prices and prices at this sales location, the Company does not believe that the fair value recorded by the Company would be significantly different from what it expects to receive upon settlement.

The Company uses the crude oil swaps classified as Level 3 to hedge against the risk of declining commodity prices and not as speculative investments. Gains or losses related to these Level 3 derivative net liabilities (including any reduction for credit risk) are deferred until the hedged commodity transaction occurs in accordance with the provisions of the existing guidance for derivative instruments and hedging activities. The Level 3 derivative Net Liabilities amount to $7.9 million at June 30, 2013 and represent 3.6% of the Total Net Assets shown in Part I, Item 1 at Note 2 – Fair Value Measurements at June 30, 2013.

The decrease in the net fair value liability of the Level 3 positions from October 1, 2012 to June 30, 2013, as shown in Part I, Item 1 at Note 2, was attributable to a decrease in the commodity price of crude oil relative to the swap price during that period. The Company believes that these fair values reasonably represent the amounts that the Company would realize upon settlement based on commodity prices that were present at June 30, 2013.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At June 30, 2013, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty (for an asset) or the Company's (for a liability) credit default swaps rates.

For a complete discussion of market risk sensitive instruments, refer to "Market Risk Sensitive Instruments" in Item 7 of the Company's 2012 Form 10-K. There have been no subsequent material changes to the Company's exposure to market risk sensitive instruments.

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Rate and Regulatory Matters

Utility Operation

Delivery rates for both the New York and Pennsylvania divisions are regulated by the states' respective public utility commissions and typically are changed only when approved through a procedure known as a "rate case." Currently neither division has a rate case on file. Proceedings concerning the New York division's current rates are discussed below. In both jurisdictions, delivery rates do not reflect the recovery of purchased gas costs. Prudently-incurred gas costs are recovered through operation of automatic adjustment clauses, and are collected primarily through a separately-stated "supply charge" on the customer bill.

New York Jurisdiction

Customer delivery rates charged by Distribution Corporation's New York division were established in a rate order issued on December 21, 2007 by the NYPSC. In connection with an efficiency and conservation program, the rate order approved a revenue decoupling mechanism. The revenue decoupling mechanism "decouples" revenues from throughput by enabling the Company to collect from small volume customers its allowed margin on average weather normalized usage per customer. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation.

Following discussions with regulatory staff with respect to earnings levels, on March 27, 2013, Distribution Corporation filed a plan ("Plan") with the NYPSC proposing to adopt an "earnings stabilization and sharing mechanism" that would allocate earnings above a rate of return on equity of 9.96% evenly between shareholders and an accounting reserve ("Reserve"). The Reserve would be utilized to stabilize Distribution Corporation's earnings and to fund customer benefit programs. The Plan also proposed to increase capital spending and to aid new customer system expansion efforts. Discussions were held with NYPSC staff and others with respect to the Plan.

In a related development, on April 19, 2013, the NYPSC issued an order directing Distribution Corporation to either agree to make its rates and charges temporary subject to refund effective June 1, 2013, or show cause why its gas rates and charges should not be set on a temporary basis subject to refund ("Order"). The Order recognized Distribution Corporation's Plan and, while acknowledging the Company's cost-cutting and efficiency achievements, determined nonetheless that the Plan did not propose to adjust "existing rates . . . enough to compensate for the imbalance between ratepayer and shareholder interests that has developed since . . . 2007 . . ." Pursuant to the Order, the NYPSC commenced a "temporary rate" proceeding and, following hearings, on June 14, 2013, the NYPSC issued an order making Distribution Corporation's rates and charges temporary and subject to refund pending the determination of permanent gas rates through further rate proceedings. Exploratory discussions for settlement of Distribution Corporation's rates and charges were commenced and are expected to continue as the formal case to establish permanent rates proceeds along a parallel path.

In addition to authorizing a "temporary rate" proceeding, the Order also suggested an examination of the applicability of a provision of New York public utility law, PSL §66(20), that provides the NYPSC with stated authority to direct a refund of revenues received by a utility "in excess of its authorized rate of return for a period of twelve months." On May 17, 2013, Distribution Corporation commenced an action in New York Supreme Court, Erie County, seeking the court's declaration that PSL §66(20) is unconstitutional and enjoining the NYPSC from issuing any orders or rules under PSL §66(20) or making any attempts to otherwise enforce the statute. On June 20, 2013 and as anticipated, the NYPSC moved to dismiss Distribution Corporation's complaint. Distribution Corporation is unable to predict the outcome of the proceedings at this time.

Pennsylvania Jurisdiction

Distribution Corporation's current delivery charges in its Pennsylvania jurisdiction were approved by the PaPUC on November 30, 2006 as part of a settlement agreement that became effective January 1, 2007.

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Pipeline and Storage

Supply Corporation currently does not have a rate case on file with the FERC. A rate settlement approved by the FERC on August 6, 2012 requires Supply Corporation to make a general rate filing no later than January 1, 2016. In addition, Supply Corporation is not barred from filing a general rate case before such date or at any time.

Empire also has no rate case currently on file with the FERC, but is not subject to any requirement to make any future general rate filing. Empire is also not barred from filing a general rate case at any time.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory policies and procedures. It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs.

The Company has agreed with the NYDEC to remediate a former manufactured gas plant site located in New York. In February 2009, the Company received approval from the NYDEC of a Remedial Design Work Plan (RDWP) for this site. In October 2010, the Company submitted a RDWP addendum to conduct additional Preliminary Design Investigation field activities necessary to design a successful remediation. As a result of this work, the Company submitted to the NYDEC a proposal to amend the NYDEC's Record of Decision remedy for the site. In April 2013, the NYDEC approved the Company's proposed amendment. Final remedial design work for the site has begun. An estimated minimum liability for remediation of this site of $13.9 million has been recorded.

At June 30, 2013, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites (including the former manufactured gas plant site discussed above) will be approximately $16.8 million. This estimated liability, which includes the $13.9 million discussed above, has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at June 30, 2013. The Company expects to recover its environmental clean-up costs through rate recovery.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. In the United States, these efforts include legislative proposals and EPA regulations at the federal level, actions at the state level, and private party litigation related to greenhouse gas emissions. While the U.S. Congress has from time to time considered legislation aimed at reducing emissions of greenhouse gases, Congress has not yet passed any federal climate change legislation and we cannot predict when or if Congress will pass such legislation and in what form. In the absence of such legislation, the EPA is regulating greenhouse gas emissions pursuant to the authority granted to it by the federal Clean Air Act. For example, in April 2012, the EPA adopted rules which restrict emissions associated with oil and natural gas drilling. Compliance with these new rules will not materially change the Company's ongoing emissions–limiting technologies and practices, and is not expected to have a significant impact on the Company. In addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. Legislation or regulation that restricts carbon emissions could increase the Company's cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state or regional climate change and greenhouse gas measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. But legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

The Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental regulations, new information or other factors could adversely impact the Company.

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New Authoritative Accounting and Financial Reporting Guidance

In December 2011, the FASB issued authoritative guidance requiring enhanced disclosures regarding offsetting assets and liabilities. Companies are required to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2014 and is not expected to have a significant impact on the Company's financial statements.

In February 2013, the FASB issued authoritative guidance requiring enhanced disclosures regarding the reporting of amounts reclassified out of accumulated other comprehensive income. The authoritative guidance requires parenthetical disclosure on the face of the financial statements or a single footnote that would provide more detail about the components of reclassification adjustments that are reclassified in their entirety to net income. If a component of a reclassification adjustment is not reclassified in its entirety to net income, a cross reference would be made to the footnote disclosure that provides a more thorough discussion of the component involved in that reclassification adjustment. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2014. The Company does not expect this guidance to have a material impact.

Safe Harbor for Forward-Looking Statements

The Company is including the following cautionary statement in this Form 10-Q to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," " "seeks," "will," "may," and similar expressions, are "forward-looking statements" as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. Factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations;

2. Changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing;

3. Changes in the price of natural gas or oil;

4. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;

5. Uncertainty of oil and gas reserve estimates;

6. Significant differences between the Company's projected and actual production levels for natural gas or oil;

7. Changes in demographic patterns and weather conditions;

8. Changes in the availability, price or accounting treatment of derivative financial instruments;

9. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, allowed rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;

10. Delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;

11. Financial and economic conditions, including the availability of credit, and occurrences affecting the Company’s ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company’s credit ratings and changes in interest rates and other capital market conditions;

12. Changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers’ ability to pay for, the Company’s products and services;

13. The creditworthiness or performance of the Company’s key suppliers, customers and counterparties;

14. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;

15. Changes in price differential between similar quantities of natural gas at different geographic locations, and the effect of such changes on the demand for pipeline transportation capacity to or from such locations;

16. Other changes in price differentials between similar quantities of oil or natural gas having different quality, heating value, geographic location or delivery date;

17. Significant differences between the Company’s projected and actual capital expenditures and operating expenses;

18. Changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company’s pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities;

19. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;

20. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or

21. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Refer to the "Market Risk Sensitive Instruments" section in Item 2 – MD&A.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company's Chief Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of June 30, 2013.

Changes in Internal Control Over Financial Reporting

On May 20, 2013, NFR implemented both Oracle PeopleSoft Financials software as its new Accounting System and a new customer billing software system that was developed internally. Both systems help support the operations of the Energy Marketing segment. These system changes are a result of an evaluation of the capability of the previous accounting and billing systems and related processes to support the evolving needs of the Energy Marketing segment and are not the result of any actual or perceived deficiencies in the current systems. These implementations resulted in certain changes to NFR's processes and internal controls impacting financial reporting. While there are inherent risks involved with the implementation of any new system, management believes that it is adequately monitoring and managing the transition, and adequately tested the systems prior to implementation.

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended June 30, 2013 and no changes through the filing date of this Quarterly Report on Form 10-Q with the SEC, other than the change that occurred on May 20, 2013, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

On November 14, 2012, the PaDEP sent a draft Consent Assessment of Civil Penalty ("Draft Consent") to a subsidiary of Midstream Corporation. The Draft Consent offers to settle various alleged violations of the Pennsylvania Clean Streams Law and the PaDEP's rules and regulations regarding erosion and sedimentation control if the Company would consent to a civil penalty. The amount of the penalty sought by the PaDEP is not material to the Company. The Company disputes many of the alleged violations and will vigorously defend its position in negotiations with the PaDEP. The alleged violations occurred during construction of the Company's Trout Run Gathering System following historic rainfall and flooding in the fall of 2011. The Company has spent over $112 million in constructing this project.

For a discussion of various environmental and other matters, refer to Part I, Item 1 at Note 6 — Commitments and Contingencies, and Part I, Item 2 - MD&A of this report under the heading "Other Matters – Environmental Matters."

For a discussion of certain rate matters involving the NYPSC, refer to Part I, Item 1 of this report at Note 9 — Regulatory Matters.

In addition to these matters, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service, and purchased gas cost issues, among other things. While these other matters arising in the normal course of business could have a material effect on earnings and cash flows in the period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

Item 1A. Risk Factors

The risk factors in Item 1A of the Company's 2012 Form 10-K, as amended by Item 1A of Part II of the Company's Form 10-Q for the quarter ended March 31, 2013, have not materially changed other than as set forth below. The risk factor presented below should be read in conjunction with the risk factors disclosed in the 2012 Form 10-K and the March 31, 2013 Form 10-Q.

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The Company’s need to comply with comprehensive, complex, and sometimes unpredictable government regulations may increase its costs and limit its revenue growth, which may result in reduced earnings.

While the Company generally refers to its Utility segment and its Pipeline and Storage segment as its “regulated segments,” there are many governmental regulations that have an impact on almost every aspect of the Company’s businesses. Existing statutes and regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Company, which may increase the Company’s costs or affect its business in ways that the Company cannot predict.

In the Company’s Utility segment, the operations of Distribution Corporation are subject to the jurisdiction of the NYPSC, the PaPUC and, with respect to certain transactions, the FERC. The NYPSC and the PaPUC, among other things, approve the rates that Distribution Corporation may charge to its utility customers. Those approved rates also impact the returns that Distribution Corporation may earn on the assets that are dedicated to those operations. If Distribution Corporation is required in a rate proceeding to reduce the rates it charges its utility customers, or to the extent Distribution Corporation is unable to obtain approval for rate increases from these regulators, particularly when necessary to cover increased costs (including costs that may be incurred in connection with governmental investigations or proceedings or mandated infrastructure inspection, maintenance or replacement programs), earnings may decrease.

In addition to their historical methods of utility regulation, both the PaPUC and NYPSC have established competitive markets in which customers may purchase gas commodity from unregulated marketers, in addition to utility companies. Retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation because in both jurisdictions it recovers its cost of service through delivery rates and charges, and not through any mark-up on the gas commodity purchased by its customers. Over the longer run, however, rate design changes resulting from further customer migration to marketer service (“unbundling”) can expose utilities such as Distribution Corporation to stranded costs and revenue erosion in the absence of compensating rate relief.

Both the NYPSC and the PaPUC have instituted proceedings for the purpose of promoting conservation of energy commodities, including natural gas. In New York, Distribution Corporation implemented a Conservation Incentive Program that promotes conservation and efficient use of natural gas by offering customer rebates for high-efficiency appliances, among other things. The intent of conservation and efficiency programs is to reduce customer usage of natural gas. Under traditional volumetric rates, reduced usage by customers results in decreased revenues to the Utility. To prevent revenue erosion caused by conservation, the NYPSC approved a “revenue decoupling mechanism” that renders Distribution Corporation’s New York division financially indifferent to the effects of conservation. In Pennsylvania, although a generic statewide proceeding is pending, the PaPUC has not yet directed Distribution Corporation to implement conservation measures. If the NYPSC were to revoke the revenue decoupling mechanism in a future proceeding or the PaPUC were to adopt a conservation program without a revenue decoupling mechanism or other changes in rate design, reduced customer usage could decrease revenues, forcing Distribution Corporation to file for rate relief.

In New York, aggressive generic statewide programs created under the label of efficiency or conservation continue to generate a sizable utility funding requirement for state agencies that administer those programs. Although utilities are authorized to recover the cost of efficiency and conservation program funding through special rates and surcharges, the resulting upward pressure on customer rates, coupled with increased assessments and taxes, could affect future tolerance for traditional utility rate increases, especially if natural gas commodity costs were to increase.

The Company is subject to the jurisdiction of the FERC with respect to Supply Corporation, Empire and some transactions performed by other Company subsidiaries, including Seneca, Distribution Corporation and NFR. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their natural gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. Pursuant to the petition of a customer or state commission, or on the FERC's own initiative, the FERC has the authority to investigate whether Supply Corporation's and Empire's rates are still "just and reasonable" as required by the NGA, and if not, to reduce those rates prospectively. If Supply Corporation or Empire is required in a rate proceeding to reduce the rates it charges its natural gas transportation and/or storage customers, or if either Supply Corporation or Empire is unable to obtain approval for rate increases, particularly when necessary to cover increased costs, Supply Corporation's or Empire's earnings may decrease. The FERC also possesses significant penalty authority with respect to violations of the laws and regulations it administers. Supply Corporation, Empire and, to the extent subject to FERC jurisdiction, the Company's other subsidiaries are subject to the FERC's penalty authority. In addition, the FERC exercises jurisdiction over the construction and operation of facilities used in interstate gas transmission. Also, decisions of Canadian regulators such as the National Energy Board and the Ontario Energy Board could affect the viability and profitability of Supply Corporation and Empire projects designed to transport gas from New York into Ontario.

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In January 2012 President Obama signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act. The legislation increases civil penalties for pipeline safety violations and addresses matters such as pipeline damage prevention, automatic and remote-controlled shut-off valves, excess flow valves, pipeline integrity management, documentation and testing of maximum allowable operating pressure, and reporting of pipeline accidents. The legislation requires the Pipeline and Hazardous Materials Safety Administration (PHMSA) to issue or revise certain regulations and to conduct various reviews, studies and evaluations. In addition, PHMSA in August 2011 issued an Advance Notice of Proposed Rulemaking regarding pipeline safety. As described in the notice, PHMSA is considering regulations regarding, among other things, the designation of additional high consequence areas along pipelines, minimum requirements for leak detection systems, installation of emergency flow restricting devices, and revision of valve spacing requirements. Unrelated to these safety initiatives, the EPA in April 2010 issued an Advance Notice of Proposed Rulemaking reassessing its regulations governing the use and distribution in commerce of PCBs. The EPA had projected that it may issue a Notice of Proposed Rulemaking by April 2013, but it has not done so. If as a result of these or similar new laws or regulations the Company incurs material costs that it is unable to recover fully through rates or otherwise offset, the Company’s financial condition, results of operations, and cash flows would be adversely affected.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

On April 1, 2013, the Company issued a total of 4,400 unregistered shares of Company common stock to the eight non-employee directors of the Company then serving on the Board of Directors of the Company, 550 shares to each such director. All of these unregistered shares were issued under the Company’s 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors’ services during the quarter ended June 30, 2013. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[a]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs [b]
Apr. 1 - 30, 2013	6,430	$ 58.73	-	6,971,019

May 1 - 31, 2013	18,560	$ 63.03	-	6,971,019
June 1 - 30, 2013	6,599	$ 58.97	-	6,971,019
Total	31,589	$ 61.31	-	6,971,019

[a] Represents (i) shares of common stock of the Company purchased on the open market with Company "matching contributions" for the accounts of participants in the Company's 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock options, SARs or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the quarter ended June 30, 2013, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 31,589 shares purchased other than through a publicly announced share repurchase program, 18,588 were purchased for the Company's 401(k) plans and 13,001 were purchased as a result of shares tendered to the Company by holders of stock options, SARs or shares of restricted stock.

[b] In September 2008, the Company's Board of Directors authorized the repurchase of eight million shares of the Company's common stock. The repurchase program has no expiration date. The Company, however, stopped repurchasing shares after September 17, 2008. Since that time, the Company has increased its emphasis on Marcellus Shale development and pipeline expansion. As such, the Company does not anticipate repurchasing any shares in the near future.

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Item 6. Exhibits

Exhibit Number	Description of Exhibit
•	National Fuel Gas Company By-Laws as amended June 13, 2013 (Exhibit 3.1, Form 8-K dated June 13, 2013).
12	Statements regarding Computation of Ratios:
	Ratio of Earnings to Fixed Charges for the Twelve Months Ended June 30, 2013 and the Fiscal Years Ended September 30, 2009 through 2012.
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
32••	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	National Fuel Gas Company Consolidated Statements of Income for the Twelve Months Ended June 30, 2013 and 2012.
101	Interactive data files submitted pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the three and nine months ended June 30, 2013 and 2012, (ii) the Consolidated Statements of Comprehensive Income for the three and nine months ended June 30, 2013 and 2012, (iii) the Consolidated Balance Sheets at June 30, 2013 and September 30, 2012, (iv) the Consolidated Statements of Cash Flows for the nine months ended June 30, 2013 and 2012 and (v) the Notes to Condensed Consolidated Financial Statements.

• Incorporated herein by reference as indicated.

•• In accordance with Item 601(b)(32)(ii) of Regulation S-K and SEC Release Nos. 33-8238 and 34-47986, Final Rule: Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, the material contained in Exhibit 32 is "furnished" and not deemed "filed" with the SEC and is not to be incorporated by reference into any filing of the Registrant under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing, except to the extent that the Registrant specifically incorporates it by reference.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NATIONAL FUEL GAS COMPANY
(Registrant)

/s/ D. P. Bauer
D. P. Bauer
Treasurer and Principal Financial Officer

/s/ K. M. Camiolo
K. M. Camiolo
Controller and Principal Accounting Officer

Date: August 9, 2013