NATIONAL FUEL GAS CO
Form 10-Q
August 08, 2014
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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, 2014
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, 2014: 84,115,604 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	
2013 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2013
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.
FERC 7(c) application	An application to the FERC under Section 7(c) of the federal Natural Gas Act for authority to construct, operate (and provide services through) facilities to transport or store natural gas in interstate commerce.
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.
ICE	Intercontinental Exchange. An exchange which maintains a futures market for crude oil and 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.
LDC	Local distribution company
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)
NEPA	National Environmental Policy Act of 1969, as amended
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.

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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.
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)

(Thousands of Dollars, Except Per Common Share Amounts)	Three Months Ended June 30, 2014	2013	Nine Months Ended June 30, 2014	2013
INCOME				
Operating Revenues	$440,144	$440,008	$1,746,458	$1,490,688
Operating Expenses				
Purchased Gas	86,628	95,164	577,005	426,900
Operation and Maintenance	107,232	108,497	352,794	338,533
Property, Franchise and Other Taxes	22,483	21,201	69,114	63,550
Depreciation, Depletion and Amortization	96,788	88,142	279,876	240,503
	313,131	313,004	1,278,789	1,069,486
Operating Income	127,013	127,004	467,669	421,202
Other Income (Expense):				
Interest Income	370	317	1,321	1,844
Other Income	1,496	1,163	6,847	3,666
Interest Expense on Long-Term Debt	(22,116)	(22,998)	(67,767)	(67,232)
Other Interest Expense	(1,136)	(1,303)	(3,460)	(2,898)
Income Before Income Taxes	105,627	104,183	404,610	356,582
Income Tax Expense	41,107	45,688	162,627	144,423
Net Income Available for Common Stock	64,520	58,495	241,983	212,159
EARNINGS REINVESTED IN THE BUSINESS				
Balance at Beginning of Period	1,557,184	1,398,999	1,442,617	1,306,284
	1,621,704	1,457,494	1,684,600	1,518,443
Dividends on Common Stock	(32,373)	(31,346)	(95,269)	(92,295)
Balance at June 30	$1,589,331	$1,426,148	$1,589,331	$1,426,148
Earnings Per Common Share:				
Basic:				
Net Income Available for Common Stock	$0.77	$0.70	$2.89	$2.54
Diluted:				
Net Income Available for Common Stock	$0.76	$0.69	$2.85	$2.52
Weighted Average Common Shares Outstanding:				
Used in Basic Calculation	84,029,124	83,557,968	83,863,764	83,481,849
Used in Diluted Calculation	84,973,100	84,325,465	84,892,473	84,242,128
Dividends Per Common Share:				
Dividends Declared	$0.385	$0.375	$1.135	$1.105

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Statements of Comprehensive Income
(Unaudited)

	Three Months Ended June 30,		Nine Months Ended June 30,	
(Thousands of Dollars)	2014	2013	2014	2013
Net Income Available for Common Stock	$64,520	$58,495	$241,983	$212,159
Other Comprehensive Income (Loss), Before Tax:				
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	1,191	331	4,311	3,104
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(13,221)	101,866	(77,903)	89,865
Reclassification Adjustment for Realized (Gains) Losses on Securities Available for Sale in Net Income	16	—	16	—
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	14,464	(1,885)	30,921	(23,973)
Other Comprehensive Income (Loss), Before Tax	2,450	100,312	(42,655)	68,996
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	420	123	1,576	1,160
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(7,656)	42,566	(34,968)	37,490
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Securities Available for Sale in Net Income	7	—	7	—
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	8,262	(791)	15,134	(10,065)
Income Taxes – Net	1,033	41,898	(18,251)	28,585
Other Comprehensive Income (Loss)	1,417	58,414	(24,404)	40,411
Comprehensive Income	$65,937	$116,909	$217,579	$252,570

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	June 30, 2014	September 30, 2013
ASSETS		
Property, Plant and Equipment	$7,951,544	$7,313,203
Less - Accumulated Depreciation, Depletion and Amortization	2,413,958	2,161,477
	5,537,586	5,151,726
Current Assets		
Cash and Temporary Cash Investments	102,653	64,858
Hedging Collateral Deposits	—	1,094
Receivables – Net of Allowance for Uncollectible Accounts of $36,197 and $27,144, Respectively	202,437	133,182
Unbilled Revenue	22,225	19,483
Gas Stored Underground	20,183	51,484
Materials and Supplies - at average cost	25,620	29,904
Unrecovered Purchased Gas Costs	—	12,408
Other Current Assets	49,412	56,905
Deferred Income Taxes	47,153	79,359
	469,683	448,677
Other Assets		
Recoverable Future Taxes	162,138	163,355
Unamortized Debt Expense	14,891	16,645
Other Regulatory Assets	241,640	252,568
Deferred Charges	10,245	9,382
Other Investments	87,855	96,308
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	29,532	22,774
Fair Value of Derivative Financial Instruments	28,779	48,989
Other	633	2,447
	581,189	617,944
Total Assets	$6,588,458	$6,218,347

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	June 30, 2014	September 30, 2013
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued And Outstanding – 84,086,437 Shares and 83,661,969 Shares, Respectively	$84,086	$83,662
Paid in Capital	710,924	687,684
Earnings Reinvested in the Business	1,589,331	1,442,617
Accumulated Other Comprehensive Loss	(43,638)	(19,234)
Total Comprehensive Shareholders' Equity	2,340,703	2,194,729
Long-Term Debt, Net of Current Portion	1,649,000	1,649,000
Total Capitalization	3,989,703	3,843,729
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	—
Current Portion of Long-Term Debt	—	—
Accounts Payable	145,357	105,283
Amounts Payable to Customers	32,805	12,828
Dividends Payable	32,373	31,373
Interest Payable on Long-Term Debt	18,195	29,960
Customer Advances	81	21,959
Customer Security Deposits	16,166	16,183
Other Accruals and Current Liabilities	154,145	83,946
Fair Value of Derivative Financial Instruments	28,683	639
	427,805	302,171
Deferred Credits		
Deferred Income Taxes	1,409,997	1,347,007
Taxes Refundable to Customers	90,463	85,655
Unamortized Investment Tax Credit	1,253	1,579
Cost of Removal Regulatory Liability	166,996	157,622
Other Regulatory Liabilities	90,643	61,549
Pension and Other Post-Retirement Liabilities	152,174	158,014
Asset Retirement Obligations	121,760	119,511
Other Deferred Credits	137,664	141,510
	2,170,950	2,072,447
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$6,588,458	$6,218,347

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, 2014	2013
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$241,983	$212,159
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	279,876	240,503
Deferred Income Taxes	119,395	141,007
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(4,641)	(4,314)
Stock-Based Compensation	12,438	9,706
Other	10,969	10,038
Change in:		
Hedging Collateral Deposits	1,094	(330)
Receivables and Unbilled Revenue	(72,082)	(43,138)
Gas Stored Underground and Materials and Supplies	35,503	24,551
Unrecovered Purchased Gas Costs	12,408	—
Other Current Assets	5,376	14,228
Accounts Payable	26,386	11,241
Amounts Payable to Customers	19,977	(7,578)
Customer Advances	(21,878)	(23,809)
Customer Security Deposits	(17)	(1,112)
Other Accruals and Current Liabilities	17,590	3,534
Other Assets	25,449	(5,010)
Other Liabilities	15,743	5,557
Net Cash Provided by Operating Activities	725,569	587,233
INVESTING ACTIVITIES		
Capital Expenditures	(609,427)	(513,399)
Other	4,696	(3,885)
Net Cash Used in Investing Activities	(604,731)	(517,284)
FINANCING ACTIVITIES		
Changes in Notes Payable to Banks and Commercial Paper	—	(171,000)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	4,641	4,314
Net Proceeds from Issuance of Long-Term Debt	—	495,415
Reduction of Long-Term Debt	—	(250,000)
Dividends Paid on Common Stock	(94,269)	(91,364)
Net Proceeds from Issuance of Common Stock	6,585	2,774
Net Cash Used in Financing Activities	(83,043)	(9,861)
Net Increase in Cash and Temporary Cash Investments	37,795	60,088
Cash and Temporary Cash Investments at October 1	64,858	74,494
Cash and Temporary Cash Investments at June 30	$102,653	$134,582

Supplemental Disclosure of Cash Flow Information		
Non-Cash Investing Activities:		
Non-Cash Capital Expenditures	$135,747	$58,632

See Notes to Condensed Consolidated Financial Statements

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

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, 2013, 2012 and 2011 that are included in the Company's 2013 Form 10-K. The consolidated financial statements for the year ended September 30, 2014 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, 2014 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2014. 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.

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. At June 30, 2014, the Company had no hedging collateral deposits outstanding. At September 30, 2013, the Company had hedging collateral deposits of $1.1 million related to its exchange-traded futures contracts. 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 $30.5 million at June 30, 2014, 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 $151.4 million and $106.1 million at June 30, 2014 and September 30, 2013, 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.

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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, 2014, the ceiling exceeded the book value of the oil and gas properties by approximately $183.1 million.

Accumulated Other Comprehensive Loss. The components of Accumulated Other Comprehensive Loss and changes for the quarter and nine months ended June 30, 2014, net of related tax effect, are as follows (amounts in parentheses indicate debits) (in thousands):

	Gains and Losses on Derivative Financial Instruments	Gains and Losses on Securities Available for Sale	Funded Status of the Pension and Other Post-Retirement Benefit Plans	Total
Three Months Ended June 30, 2014				
Balance at April 1, 2014	$2,937	$8,301	$(56,293)	$(45,055)
Other Comprehensive Gains and Losses Before Reclassifications	(5,565)	771	—	(4,794)
Amounts Reclassified From Other Comprehensive Loss	6,202	9	—	6,211
Balance at June 30, 2014	$3,574	$9,081	$(56,293)	$(43,638)
Nine Months Ended June 30, 2014				
Balance at October 1, 2013	$30,722	$6,337	$(56,293)	$(19,234)
Other Comprehensive Gains and Losses Before Reclassifications	$(42,935)	$2,735	$—	$(40,200)
Amounts Reclassified From Other Comprehensive Loss	$15,787	$9	$—	$15,796
Balance at June 30, 2014	$3,574	$9,081	$(56,293)	$(43,638)

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Reclassifications Out of Accumulated Other Comprehensive Loss. The details about the reclassification adjustments out of accumulated other comprehensive loss for the quarter and nine months ended June 30, 2014 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Loss Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Loss		Affected Line Item in the Statement Where Net Income is Presented
	Three Months Ended June 30, 2014	Nine Months Ended June 30, 2014	
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:			
Commodity Contracts	($14,547)	($27,372)	Operating Revenues
Commodity Contracts	83	(3,549)	Purchased Gas
Gains (Losses) on Securities Available for Sale	(16)	(16)	Other Income
	(14,480)	(30,937)	Total Before Income Tax
	8,269	15,141	Income Tax Expense
	($6,211)	($15,796)	Net of Tax

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

	At June 30, 2014	At September 30, 2013
Prepayments	$10,609	$10,605
Prepaid Property and Other Taxes	11,008	13,079
Federal Income Taxes Receivable	—	1,122
State Income Taxes Receivable	—	3,275
Fair Values of Firm Commitments	—	1,829
Regulatory Assets	27,795	26,995
	$49,412	$56,905

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

	At June 30, 2014	At September 30, 2013
Accrued Capital Expenditures	$82,021	$41,100
Regulatory Liabilities	14,109	20,013
Reserve for Gas Replacement	30,526	—
Federal Income Taxes Payable	709	—
State Income Taxes Payable	5,897	—
Other	20,883	22,833
	$154,145	$83,946

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 potentially dilutive securities the Company has outstanding are stock options, SARs, restricted stock units and performance shares. 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, restricted stock units and performance shares that are antidilutive are excluded from the calculation of diluted earnings per common share. There were 338 and 829 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2014, respectively. There were 180,552 and 196,121 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2013, respectively.

Stock-Based Compensation. The Company granted 116,090 performance shares during the nine months ended June 30, 2014. The weighted average fair value of such performance shares was $67.16 per share for the nine months ended June 30, 2014. Performance shares are an award constituting units denominated in common stock of the Company, the number of which may be adjusted over a performance cycle based upon the extent to which performance goals have been satisfied. Earned performance shares may be distributed in the form of shares of common stock of the Company, an equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company. The performance shares do not entitle the participant to receive dividends during the vesting period.

Half of the performance shares granted during the nine months ended June 30, 2014 must meet a performance goal related to relative return on capital over the performance cycle of October 1, 2013 to September 30, 2016. The performance goal over the performance cycle is the Company's total return on capital relative to the total return on capital of other companies in a group selected by the Compensation Committee ("Report Group"). Total return on capital for a given company means the average of the Report Group companies' returns on capital for each twelve month period corresponding to each of the Company's fiscal years during the performance cycle, based on data reported for the Report Group companies in the Bloomberg database. The number of these performance shares that will vest and be paid 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 fair value of these performance shares is calculated by multiplying the expected number of shares that will be issued by the average market price of Company common stock on the date of grant reduced by the present value of forgone dividends over the vesting term of the award. The fair value is recorded as compensation expense over the vesting term of the award. The other half of the performance shares granted during the nine months ended June 30, 2014 must meet a performance goal related to total shareholder return over the performance cycle of October 1, 2013 to September 30, 2016. The performance goal over the performance cycle is the Company's three-year total shareholder return relative to the three-year total shareholder return of the other companies in the Report Group. Three-year shareholder return for a given company will be based on the data reported for that company (with the starting and ending stock prices over the performance cycle calculated as the average closing stock price for the prior calendar month and with dividends reinvested in that company's securities at each ex-dividend date) in the Bloomberg database. The number of these performance shares that will vest and be paid 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 fair value price at the date of grant for these performance shares is determined using a Monte Carlo simulation technique, which includes a reduction in value for the present value of forgone dividends over the vesting term of the award. This price is multiplied by the number of performance shares awarded, the result of which is recorded as compensation expense over the vesting term of the award.

The Company granted 82,151 non-performance based restricted stock units during the nine months ended June 30, 2014. The weighted average fair value of such non-performance based restricted stock units was $65.24 per share for the nine months ended June 30, 2014. Restricted stock units 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. These non-performance based restricted stock units do not entitle the participant to receive dividends during the vesting period. The accounting for 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.

No stock options, SARs or restricted share awards were granted by the Company during the nine months ended June 30, 2014.

New Authoritative Accounting and Financial Reporting Guidance. In May 2014, the FASB issued authoritative guidance regarding revenue recognition. The authoritative guidance provides a single, comprehensive revenue recognition model for all contracts with customers to improve comparability. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2018 and early adoption is not permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements and disclosures.

In June 2014, the FASB issued authoritative guidance regarding accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the employee has completed the requisite service period. This authoritative guidance requires that such performance targets that affect vesting be treated as performance conditions, meaning that the performance target should not be factored in the calculation of the award at the grant date. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2017, with early adoption permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements.

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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, 2014 and September 30, 2013. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The fair value presentation for over the counter swaps has been changed to combine gas and oil swaps at both June 30, 2014 and September 30, 2013. In the September 30, 2013 Form 10-K, gas swaps were reported separately from oil swaps. This change in presentation was made because a significant number of the counterparties enter into both gas and oil swap agreements with the Company.

Recurring Fair Value Measures	At fair value as of June 30, 2014				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
Assets:					
Cash Equivalents – Money Market Mutual Funds	$86,305	$—	$—	$ —	$86,305
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	2,950	—	—	(1,069)	1,881
Over the Counter Swaps – Gas and Oil	—	56,660	—	(29,762)	26,898
Other Investments:					
Balanced Equity Mutual Fund	35,658	—	—	—	35,658
Common Stock – Financial Services Industry	7,853	—	—	—	7,853
Other Common Stock	341	—	—	—	341
Hedging Collateral Deposits	—	—	—	—	—
Total	$133,107	$56,660	$—	$ (30,831)	$158,936
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$1,069	$—	$—	$ (1,069)	$—
Over the Counter Swaps – Gas and Oil	—	55,590	2,855	(29,762)	28,683
Total	$1,069	$55,590	$2,855	$ (30,831)	$28,683
Total Net Assets/(Liabilities)	$132,038	$1,070	$(2,855)	$ —	$130,253

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Recurring Fair Value Measures	At fair value as of September 30, 2013				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[1]	Total[1]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$51,332	$—	$—	$ —	$51,332
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	2,552	—	—	(1,641)	911
Over the Counter Swaps – Gas and Oil	—	57,070	—	(9,003)	48,067
Other Investments:					
Balanced Equity Mutual Fund	31,813	—	—	—	31,813
Common Stock – Financial Services Industry	6,544	—	—	—	6,544
Other Common Stock	330	—	—	—	330
Hedging Collateral Deposits	1,094	—	—	—	1,094
Total	$93,665	$57,070	$—	$ (10,644)	$140,091
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$1,641	$—	$—	$ (1,641)	$—
Over the Counter Swaps – Gas and Oil	—	4,452	5,190	(9,003)	639
Total	$1,641	$4,452	$5,190	$ (10,644)	$639
Total Net Assets/(Liabilities)	$92,024	$52,618	$(5,190)	$ —	$139,452

(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.

Derivative Financial Instruments

At June 30, 2014 and September 30, 2013, the derivative financial instruments reported in Level 1 consist of natural gas NYMEX and ICE futures contracts used in the Company's Energy Marketing segment. Hedging collateral deposits of $1.1 million at September 30, 2013, 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, 2014 and September 30, 2013 consist of natural gas price swap agreements used in the Company's Exploration and Production and Energy Marketing segments and the majority 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 crude oil price swap agreements used in the Company's Exploration and Production segment at June 30, 2014 and September 30, 2013. 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, 2014, it was assumed that Midway Sunset oil was 98.6% of 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 96.2% to 100.6% of NYMEX. If the price of Midway Sunset oil relative to NYMEX used in the fair value measurement calculation had been 10 percentage points higher, the fair value of the Level 3 crude oil price swap agreements liability would have been approximately $4.5 million higher at June 30, 2014. If the price of Midway Sunset oil relative to NYMEX used in the fair value measurement had been 10 percentage points lower, the fair value measurement of the Level 3 crude oil price swap agreements liability would have changed from a net liability of $2.9 million to a net asset of $1.7 million at June 30, 2014. 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.

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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, 2014, 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, 2014 and 2013, respectively. For the quarters and nine months ended June 30, 2014 and June 30, 2013, 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 (amounts in parentheses indicate credits in the derivative asset/liability accounts).

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)		Total Gains/Losses			
	April 1, 2014	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, 2014
Derivative Financial Instruments[2]	$(1,371)	$1,242 [1]	$(2,726)	$—	$(2,855)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended June 30, 2014.

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

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)		Total Gains/Losses			
	October 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, 2014
Derivative Financial Instruments[2]	$(5,190)	$2,286 [1]	$49	$—	$(2,855)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the nine months ended June 30, 2014.

(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, 2013	Gains/Losses Realized and Included in	Gains/Losses Unrealized and Included in Other	Transfer In/Out of Level 3	June 30, 2013

		Earnings		Comprehensive Income (Loss)			
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.

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, 2014		September 30, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$1,649,000	$1,798,797	$1,649,000	$1,767,519

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 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.

Any 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 $44.0 million at June 30, 2014 and $57.6 million at September 30, 2013. The fair value of the equity mutual fund was $35.7 million at June 30, 2014 and $31.8 million at September 30, 2013. The gross unrealized gain on this equity mutual fund was $8.7 million at June 30, 2014 and $5.7 million at September 30, 2013. The fair value of the stock of an insurance company was $7.9 million at June 30, 2014 and $6.5 million at September 30, 2013. The gross unrealized gain on this stock was $5.4 million at June 30, 2014 and $4.1 million at September 30, 2013. 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 derivative financial instruments to manage commodity price risk in the Exploration and Production segment as well as the Energy Marketing segment. 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. These instruments are accounted for as cash flow hedges. The Company also enters into futures contracts and swaps, which are accounted for as cash flow hedges, to manage the price risk associated with forecasted gas purchases. The Company enters into futures contracts and swaps to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in value of natural gas held in storage. These instruments are accounted for as fair value hedges. The duration of the Company’s combined cash flow and fair value hedges does not typically exceed 5 years. The Exploration and Production segment holds the majority of the Company’s derivative financial instruments. The derivative financial instruments held by the Energy Marketing segment are not considered to be material to the Company.

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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, 2014 and September 30, 2013. 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, 2014, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	221.9	Bcf (short positions)
Natural Gas	3.5	Bcf (long positions)
Crude Oil	3,777,000	Bbls (short positions)

At March 31, 2014, the Company de-designated a portion of its crude oil swaps as cash flow hedges and simultaneously re-designated them as cash flow hedges using a revised effectiveness testing model. Amounts in accumulated other comprehensive loss at March 31, 2014 associated with the de-designated crude oil swaps will be amortized into the income statement as the anticipated hedged production occurs. Since the de-designated crude oil swaps were re-designated as cash flow hedges at March 31, 2014, future gains or losses on such derivatives, to the extent they are effective, will be 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. The net mark-to-market adjustment recorded in earnings related to all of the Company's crude oil swaps was a $3.6 million loss for the quarter ended June 30, 2014. The mark-to-market impact for the nine months ended June 30, 2014, including economic hedges, was a $3.6 million loss.

As of June 30, 2014, the Company had $6.2 million ($3.6 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $15.3 million ($8.7 million after tax) of unrealized losses will be reclassified into the Consolidated Statement of Income within the next 12 months as the expected sales of the underlying commodities occur. It is expected that $21.5 million ($12.3 million after tax) of unrealized gains will be reclassified into the Consolidated Statement of Income after 12 months as the expected sales of the underlying commodities occur.

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

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended June 30, 2014 and 2013 (Thousands of Dollars)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive	Location of Derivative Gain or (Loss) Reclassified from Accumulated	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other	Location of Derivative Gain or (Loss) Recognized in the Consolidated	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion

	Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Three Months Ended June 30,		Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Three Months Ended June 30,		Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	and Amount Excluded from Effectiveness Testing) for the Three Months Ended June 30,	
	2014	2013		2014	2013		2014	2013
Commodity Contracts	$(13,832)	$99,987	Operating Revenue	$(14,547)	$1,960	Operating Revenue	$(3,593)	$456
Commodity Contracts	$611	$1,879	Purchased Gas	$83	$(75)	Not Applicable	$—	$—
Total	$(13,221)	$101,866		$(14,464)	$1,885		$(3,593)	$456

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The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Nine Months Ended June 30, 2014 and 2013 (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,		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,		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,	
	2014	2013		2014	2013		2014	2013
Commodity Contracts	$(72,950)	$86,237	Operating Revenue	$(27,372)	$24,878	Operating Revenue	$(2,819)	$—
Commodity Contracts	$(4,953)	$3,628	Purchased Gas	$(3,549)	$(905)	Not Applicable	$—	$—
Total	$(77,903)	$89,865		$(30,921)	$23,973		$(2,819)	$—

Fair Value Hedges

The Company 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, 2014, the Company’s Energy Marketing segment had fair value hedges covering approximately 9.6 Bcf (9.2 Bcf of fixed price sales commitments and 0.4 Bcf of fixed price purchase commitments). 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.

Derivatives in Fair Value Hedging Relationships	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, 2014 (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, 2014 (In Thousands)
Commodity Contracts	Operating Revenues	$2,997	$(2,997)

Commodity Contracts	Purchased Gas	$(475	) $475	
		$2,522	$(2,522	)

Credit Risk

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 fifteen counterparties of which four are in a net gain position. On average, the Company had $6.7 million of credit exposure per counterparty in a gain position at June 30, 2014. The maximum

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credit exposure per counterparty in a gain position at June 30, 2014 was $12.2 million. As of June 30, 2014, no collateral was received from the counterparties by the Company. 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, 2014, twelve of the fifteen 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, 2014, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $26.2 million according to the Company's internal model (discussed in Note 2 — Fair Value Measurements). At June 30, 2014, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $21.9 million according to the Company's internal model (discussed in Note 2 — Fair Value Measurements). For its over-the-counter swap agreements, no hedging collateral deposits were required to be posted by the Company at June 30, 2014.

For its exchange traded futures contracts, which are in an asset position, no hedging collateral deposits were required to be posted by the Company as of June 30, 2014. 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 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, 2014	2013
Current Income Taxes		
Federal	$31,496	$(518)
State	11,736	3,934
Deferred Income Taxes		
Federal	90,693	105,362
State	28,702	35,645
	162,627	144,423
Deferred Investment Tax Credit	(326)	(320)

Total Income Taxes	$162,301	$144,103
Presented as Follows:		
Other Income	(326)	(320)
Income Tax Expense	162,627	144,423
Total Income Taxes	$162,301	$144,103

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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, 2014	2013
U.S. Income Before Income Taxes	$404,284	$356,262
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$141,499	$124,692
Increase (Reduction) in Taxes Resulting from:		
State Income Taxes	26,285	25,726
Miscellaneous	(5,483)	(6,315)
Total Income Taxes	$162,301	$144,103

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

	At June 30, 2014	At September 30, 2013
Deferred Tax Liabilities:		
Property, Plant and Equipment	$1,584,856	$1,504,187
Pension and Other Post-Retirement Benefit Costs	122,864	124,021
Other	55,718	75,419
Total Deferred Tax Liabilities	1,763,438	1,703,627
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(137,992)	(130,256)
Tax Loss Carryforwards	(160,588)	(215,262)
Other	(102,014)	(90,461)
Total Deferred Tax Assets	(400,594)	(435,979)
Total Net Deferred Income Taxes	$1,362,844	$1,267,648
Presented as Follows:		
Net Deferred Tax Liability/(Asset) – Current	(47,153)	(79,359)
Net Deferred Tax Liability – Non-Current	1,409,997	1,347,007
Total Net Deferred Income Taxes	$1,362,844	$1,267,648

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 $4.6 million and $0.7 million relating to the excess stock-based compensation deductions were recorded in Paid in Capital during the nine months ended June 30, 2014 and the year ended September 30, 2013, respectively. Cumulative tax benefits of $34.2 million and $36.4 million remain at June 30, 2014 and September 30, 2013, 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 $90.5 million and $85.7 million at June 30, 2014 and September 30, 2013, 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 $162.1 million and $163.4 million at June 30, 2014 and September 30, 2013, respectively.

During the quarter ended June 30, 2014, the balance of unrecognized tax benefits increased by $1.1 million (net) as a result of positions taken on the recently filed federal tax return offset by a favorable resolution with taxing authorities (discussed

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below). Approximately $3.1 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 $3.1 million of the balance of uncertain tax positions may occur as a result of potential settlements with taxing authorities within the next twelve months.

The Internal Revenue Service (IRS) is currently conducting examinations of the Company for fiscal 2013 and fiscal 2014 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 year ended September 30, 2013, local IRS examiners issued no-change reports for fiscal 2009, fiscal 2010 and fiscal 2011. During the quarter ended June 30, 2014, local IRS examiners issued a no-change report for fiscal 2012. The IRS has reserved the right to re-examine these years, pending the anticipated issuance of IRS guidance addressing the issue for natural gas utilities.

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 March 31, 2014, the New York State fiscal year 2014-2015 Executive Budget legislation was signed into law. This legislation included numerous tax provisions, including a reduction of the corporate tax rate from 7.1% to 6.5%, effective for tax years beginning after January 1, 2016. This provision resulted in a tax benefit of approximately $2.8 million, which is reflected in the accompanying financial statements.

Note 5 - Capitalization

Common Stock. During the nine months ended June 30, 2014, the Company issued 391,397 original issue shares of common stock as a result of stock option and SARs exercises and 10,832 original issue shares of common stock for restricted stock units that vested. In addition, the Company issued 70,643 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 51,070 original issue shares of common stock for the Company's 401(k) plans. The Company also issued 11,562 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, 2014. Holders of stock options, SARs, restricted share awards or restricted stock units 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, 2014, 107,702 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. There were also 3,334 restricted stock award shares forfeited during the nine months ended June 30, 2014.

Current Portion of Long-Term Debt. None of the Company's long-term debt at June 30, 2014 will mature within the following twelve-month period.

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.

At June 30, 2014, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be approximately $14.2 million. The Company expects to recover such environmental clean-up costs through rate recovery over a period of approximately 12 years.

The Company's estimated liability for clean-up costs discussed above includes a $12.8 million estimated liability 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

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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.

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.

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 five segments: Exploration and Production, Pipeline and Storage, Gathering, Utility 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 2013 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 2013 Form 10-K. A listing of segment assets at June 30, 2014 and September 30, 2013 is shown in the tables below. Energy Marketing segment revenue from external customers and net income for the quarter ended June 30, 2014 reflect a decrease of $24.0 million and $0.5 million, respectively, in unbilled revenue and related margin (net of tax). For the nine months ended June 30, 2014, Energy Marketing segment revenue from external customers and net income reflect the impact of $9.7 million and $0.3 million, respectively, of unbilled revenue and related incremental margin (net of tax). In prior periods, Energy Marketing segment revenues and related purchased gas costs were recorded when billed, resulting in a one month lag. The impact of not recording unbilled revenue and related costs was immaterial in all prior periods.

Quarter Ended June 30, 2014 (Thousands)

	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$201,522	$48,046	$343	$143,760	$45,737	$439,408	$497	$239	$440,144
Intersegment Revenues	$—	$20,489	$18,740	$3,654	$678	$43,561	$—	$(43,561)	$—
	$32,421	$17,934	$8,717	$4,826	$602	$64,500	$24	$(4)	$64,520

Segment Profit:
Net Income
(Loss)

Nine Months Ended June 30, 2014 (Thousands)

	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$594,129	$152,829	$772	$751,861	$243,335	$1,742,926	$2,795	$737	$1,746,458
Intersegment Revenues	$—	$63,463	$48,541	$16,565	$938	$129,507	$—	$(129,507)	$—
Segment Profit: Net Income	$87,908	$58,444	$22,188	$64,586	$5,971	$239,097	$978	$1,908	$241,983

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(Thousands)	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Segment Assets:									
At June 30, 2014	$2,943,692	$1,304,619	$292,630	$1,952,626	$87,367	$6,580,934	$96,192	$(88,668)	$6,588,458
At September 30, 2013	$2,746,233	$1,246,027	$203,323	$1,870,587	$67,267	$6,133,437	$95,793	$(10,883)	$6,218,347

Quarter Ended June 30, 2013 (Thousands)

	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$195,213	$43,055	$342	$141,257	$59,128	$438,995	$779	$234	$440,008
Intersegment Revenues	$—	$21,708	$10,244	$3,305	$446	$35,703	$—	$(35,703)	$—
Segment Profit: Net Income (Loss)	$31,734	$14,075	$4,407	$7,630	$963	$58,809	$92	$(406)	$58,495

Nine Months Ended June 30, 2013 (Thousands)

	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$518,742	$132,897	$868	$653,211	$182,282	$1,488,000	$2,030	$658	$1,490,688
Intersegment Revenues	$—	$68,216	$23,622	$14,012	$1,080	$106,930	$—	$(106,930)	$—
Segment Profit: Net Income (Loss)	$86,125	$47,803	$9,442	$65,024	$5,741	$214,135	$7	$(1,983)	$212,159

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Note 8 – Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

	Retirement Plan		Other Post-Retirement Benefits	
Three Months Ended June 30,	2014	2013	2014	2013
Service Cost	$2,997	$3,961	$735	$1,176
Interest Cost	10,893	9,124	5,327	4,803
Expected Return on Plan Assets	(14,993)	(14,336)	(9,356)	(8,218)
Amortization of Prior Service Cost (Credit)	52	60	(534)	(534)
Amortization of Transition Amount	—	—	—	2
Amortization of Losses	9,002	13,194	661	5,223
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	456	(3,854)	5,325	2,393
Net Periodic Benefit Cost	$8,407	$8,149	$2,158	$4,845

	Retirement Plan		Other Post-Retirement Benefits	
Nine Months Ended June 30,	2014	2013	2014	2013
Service Cost	$8,990	$11,884	$2,204	$3,529
Interest Cost	32,681	27,373	15,981	14,409
Expected Return on Plan Assets	(44,980)	(43,009)	(28,067)	(24,654)
Amortization of Prior Service Cost (Credit)	157	179	(1,604)	(1,604)
Amortization of Transition Amount	—	—	—	6
Amortization of Losses	27,005	39,582	1,984	15,669
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	10,591	(5,813)	19,314	11,555
Net Periodic Benefit Cost	$34,444	$30,196	$9,812	$18,910

[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, 2014, the Company contributed $30.0 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $2.0 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2014, the Company expects its contributions to the Retirement Plan to be in the range of zero to $5.0 million. 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 2014 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 2014, the Company expects to make no further contributions to its VEBA trusts and 401(h) accounts.

Note 9 – Regulatory Matters

Following informal discussions, 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 stated, among other things, that there was an "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. Discussions for settlement of Distribution Corporation’s rates and charges were commenced while the formal case to establish permanent rates proceeded along a parallel path.

On December 6, 2013, Distribution Corporation filed an agreement, executed by five of the six active parties in the rate proceeding, for settlement of the temporary rate proceeding and all issues relating to rates. The settlement agreement extends customer rates at the levels previously established in 2007 for a minimum two-year term retroactive to October 1, 2013. Although customer rates were not changed, the parties agreed that the allowed rate of return on equity would be set, for ratemaking purposes, at 9.1%. Following conventional practice in New York, the agreement authorizes an “earnings sharing mechanism” (“ESM”). The ESM distributes earnings above the allowed rate of return as follows: from 9.5% to 10.5%, 50% would be allocated to shareholders, and 50% will be deferred for the benefit of customers; above 10.5%, 20% would be allocated to shareholders and 80% will be deferred for the benefit of customers. The agreement further authorizes, and rates reflect, an increase in Distribution Corporation’s pipeline replacement spending by $8.2 million per year. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. The Consolidated Balance Sheet at September 30, 2013 reflected a $7.5 million refund provision related to the settlement agreement. This amount has been passed back to ratepayers as of June 30, 2014.

The NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014.

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 company that owns a number of subsidiary operating companies, and reports financial results in five reportable business segments. For the quarter ended June 30, 2014 compared to the quarter ended June 30, 2013, the Company experienced an increase in earnings of $6.0 million. For the nine months ended June 30, 2014 compared to the nine months ended June 30, 2013, the Company experienced an increase in earnings of $29.8 million. The earnings increase for the quarter ended June 30, 2014 is primarily due to higher earnings in the Pipeline and Storage segment, Gathering segment and Exploration and Production segment, partly offset by lower earnings in the Utility segment. The earnings increase for the nine-months ended June 30, 2014 reflects higher earnings in the Pipeline and Storage segment, Gathering segment, Exploration and Production segment and the Corporate category, slightly offset by lower earnings in the Utility segment. 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 780,000 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 925 Bcf at September 30, 2012 to 1,239 Bcf at September 30, 2013. 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, 2014, the Company's Exploration and Production segment had capital expenditures of $381.9 million in the Appalachian region, of which $368.0 million was spent towards the development of the Marcellus Shale. The amount spent towards the development of the Marcellus Shale represented approximately 55% of the Company's capital expenditures for the nine months ended June 30, 2014.

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. It is expected that the Company will use short-term debt as necessary during fiscal 2014 to help meet its capital expenditure needs. The Company anticipates that it will issue long-term debt during fiscal 2015 to help meet its capital expenditure needs.

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 2013 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 2013 Form 10-K and Item 2 of the Company's December 31, 2013 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, 2014, the ceiling exceeded the book value of the oil and gas properties by approximately $183.1 million. The

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12-month average of the first day of the month price for crude oil for each month during the twelve months ended June 30, 2014, based on posted Midway Sunset prices, was $98.99 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, 2014, based on the quoted Henry Hub spot price for natural gas, was $4.12 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, 2014.) If natural gas average prices used in the ceiling test calculation at June 30, 2014 had been $1 per MMBtu lower, the book value of the Company’s oil and gas properties would have exceeded the ceiling by approximately $146.2 million, which would have resulted in an impairment charge. If crude oil average prices used in the ceiling test calculation at June 30, 2014 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company’s oil and gas properties by approximately $142.2 million. If both natural gas and crude oil average prices used in the ceiling test calculation at June 30, 2014 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 $187.1 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 2013 Form 10-K.

RESULTS OF OPERATIONS

Earnings

The Company’s earnings were $64.5 million for the quarter ended June 30, 2014 compared with earnings of $58.5 million for the quarter ended June 30, 2013. The increase in earnings of $6.0 million is primarily a result of higher earnings in the Pipeline and Storage segment, Gathering segment, Exploration and Production segment and Corporate category. Lower earnings in the Utility segment, Energy Marketing segment and All Other category partially offset these increases.

The Company’s earnings were $242.0 million for the nine months ended June 30, 2014 compared to earnings of $212.2 million for the nine months ended June 30, 2013. The increase in earnings of $29.8 million is primarily a result of higher earnings in the Pipeline and Storage segment, Gathering segment, Exploration and Production segment, Energy Marketing segment, Corporate category and All Other category. Lower earnings in the Utility segment slightly offset these increases.

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,		
(Thousands)	2014	2013	Increase (Decrease)	2014	2013	Increase (Decrease)
Exploration and Production	$32,421	$31,734	$687	$87,908	$86,125	$1,783
Pipeline and Storage	17,934	14,075	3,859	58,444	47,803	10,641
Gathering	8,717	4,407	4,310	22,188	9,442	12,746
Utility	4,826	7,630	(2,804)	64,586	65,024	(438)
Energy Marketing	602	963	(361)	5,971	5,741	230

Total Reportable Segments	64,500	58,809	5,691	239,097	214,135	24,962
All Other	24	92	(68)	978	7	971
Corporate	(4)	(406)	402	1,908	(1,983)	3,891
Total Consolidated	$64,520	$58,495	$6,025	$241,983	$212,159	$29,824

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Exploration and Production

Exploration and Production Operating Revenues

(Thousands)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Increase (Decrease)	Nine Months Ended June 30, 2014	Nine Months Ended June 30, 2013	Increase (Decrease)
Gas (after Hedging)	$127,493	$124,290	$3,203	$374,738	$309,288	$65,450
Oil (after Hedging)	76,415	69,408	7,007	216,750	206,903	9,847
Gas Processing Plant	1,100	1,124	(24)	3,827	3,151	676
Other	(3,486)	391	(3,877)	(1,186)	(600)	(586)
	$201,522	$195,213	$6,309	$594,129	$518,742	$75,387

Production Volumes

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Increase (Decrease)	Nine Months Ended June 30, 2014	Nine Months Ended June 30, 2013	Increase (Decrease)
Gas Production (MMcf)						
Appalachia	35,098	29,038	6,060	98,640	72,518	26,122
West Coast	776	780	(4)	2,403	2,240	163
Total Production	35,874	29,818	6,056	101,043	74,758	26,285
Oil Production (Mbbl)						
Appalachia	6	9	(3)	23	21	2
West Coast	777	700	77	2,230	2,093	137
Total Production	783	709	74	2,253	2,114	139

Average Prices

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Increase (Decrease)	Nine Months Ended June 30, 2014	Nine Months Ended June 30, 2013	Increase (Decrease)
Average Gas Price/Mcf						
Appalachia	$3.81	$3.97	$(0.16)	$3.84	$3.58	$0.26
West Coast [1]	$7.02	$6.89	$0.13	$6.85	$6.61	$0.24
Weighted Average	$3.88	$4.04	$(0.16)	$3.91	$3.67	$0.24
Weighted Average After Hedging	$3.55	$4.17	$(0.62)	$3.71	$4.14	$(0.43)
Average Oil Price/Bbl						
Appalachia	$100.91	$95.06	$5.85	$96.76	$93.18	$3.58
West Coast	$101.83	$101.05	$0.78	$99.82	$102.44	$(2.62)
Weighted Average	$101.82	$100.98	$0.84	$99.79	$102.35	$(2.56)
Weighted Average After Hedging	$97.54	$97.90	$(0.36)	$96.19	$97.88	$(1.69)

(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.

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2014 Compared with 2013

Operating revenues for the Exploration and Production segment increased $6.3 million for the quarter ended June 30, 2014 as compared with the quarter ended June 30, 2013. Gas production revenue after hedging increased $3.2 million due to an increase in production, which was partially offset by a $0.62 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. In addition, crude oil production revenue after hedging increased $7.0 million due to an increase in production as the weighted average price of crude oil after hedging remained largely unchanged compared to the quarter ended June 30, 2013. The increase in crude oil production was largely due to increased development in the East Coalinga, Sespe, and South Midway Sunset fields in California. These increases were partially offset by $3.9 million reduction in other revenues due to $4.0 million in mark-to-market adjustments related to hedging ineffectiveness associated with certain crude oil hedges during the quarter ended June 30, 2014.

Operating revenues for the Exploration and Production segment increased $75.4 million for the nine months ended June 30, 2014 as compared with the nine months ended June 30, 2013. Gas production revenue after hedging increased $65.5 million due to an increase in production, which was partially offset by a $0.43 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. In addition, crude oil production revenue after hedging increased $9.8 million due to an increase in production, which was partially offset by a $1.69 per barrel decrease in the weighted average price of crude oil after hedging. The increase in crude oil production was largely due to increased development in the East Coalinga, Sespe and South Midway Sunset fields in California. The change in other revenues was insignificant as the settlement proceeds related to former insurance policies ($1.9 million) and the non-recurrence of a royalty adjustment (including interest) recorded in 2013 ($1.8 million) was largely offset by the impact of mark-to-market adjustments related to hedging ineffectiveness associated with certain crude oil hedges ($3.6 million).

The Exploration and Production segment's earnings for the quarter ended June 30, 2014 were $32.4 million, an increase of $0.7 million when compared with earnings of $31.7 million for the quarter ended June 30, 2013. Higher natural gas and crude oil production increased earnings by $16.4 million and $4.7 million, respectively. In addition, the impact of lower income taxes ($6.7 million) and the reversal of an accrual for certain plugging and abandonment costs associated with offshore properties no longer owned by the Exploration and Production segment ($2.7 million) further increased earnings. The decrease in income taxes is primarily related to the reevaluation of this segment's deferred state income tax liability in Pennsylvania. In June 2013, the Exploration and Production segment recorded a $5.0 million increase to its deferred state income tax liability that did not recur during the quarter ended June 30, 2014. These earning increases were largely offset by lower natural gas and crude oil prices, after hedging, that decreased earnings by $14.3 million and $0.2 million, respectively. In addition, mark-to-market adjustments (as discussed above) further reduced earnings by $2.6 million. Earnings were further decreased by higher production costs ($6.5 million), higher depletion ($5.0 million), higher general, administrative and other expenses ($0.9 million), and higher property and other taxes ($0.6 million). The increase in production costs is largely attributable to higher transportation costs, which is due to an increase in Appalachian production. 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 general, administrative and other expenses was largely attributable to increased plugging and abandonment costs. The increase in property and other taxes was largely attributable to an increase in ad valorem and property taxes (due to an overall increase in property tax rates in California and higher impact fees in Pennsylvania).

The Exploration and Production segment's earnings for the nine months ended June 30, 2014 were $87.9 million, an increase of $1.8 million when compared with earnings of $86.1 million for the nine months ended June 30, 2013. The increase in earnings was largely attributable to higher natural gas production ($70.7 million) and crude oil production ($8.9 million). Settlement proceeds related to former insurance policies and the impact related to the non-recurrence of a royalty adjustment (including interest expense) recorded in 2013 contributed $1.3 million and $1.2 million, respectively, to earnings. In addition, the impact of lower income taxes ($2.8 million) further increased earnings. During the quarter ended March 31, 2014, the New York State fiscal year 2014-2015 Executive Budget legislation was signed into law, which included a reduction of the corporate tax rate, resulting in a deferred tax benefit of approximately $2.8 million. This deferred tax benefit was partially offset by a $0.8 million increase in deferred income tax expense associated with the impact of reevaluating this segment’s deferred state income tax liability in Pennsylvania. During the quarter ended March 31, 2014, the Exploration and Production segment recorded a $5.8 million increase to its deferred state income tax liability in Pennsylvania. As noted above, a similar reevaluation in June 2013 resulted in a $5.0 million increase in that year, resulting in a year over year increase of $0.8 million in deferred income tax expense. These earnings increases were partially offset by lower natural gas and crude oil prices, after hedging, which decreased earnings by $28.1 million and $2.5 million, respectively. Earnings were further decreased by higher production costs ($20.5 million), higher depletion ($24.0 million), the impact of mark-to-market adjustments ($2.3 million), higher general, administrative and other expenses ($1.6 million), higher property and other taxes ($2.4 million), and higher interest expense ($1.6 million). The increase in production costs is largely attributable to higher transportation costs, which is due to an increase in Appalachian production. 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 general, administrative and other expenses was largely due to higher personnel costs and the accrual of plugging and abandonment costs associated with offshore properties no longer owned by the Exploration and Production segment. The increase in property and other taxes was largely attributable to an increase in ad valorem and property taxes (due to an acquisition of properties in the East Coalinga Field in Fresno County, California in the second quarter of 2013 and an overall increase in property tax rates in California, and higher impact fees in Pennsylvania). 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 of the Company's $500 million long-term debt issuance in February 2013.

Pipeline and Storage

Pipeline and Storage Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2014	2013	Increase (Decrease)	2014	2013	Increase (Decrease)
Firm Transportation	$50,142	$45,809	$4,333	$158,580	$143,041	$15,539
Interruptible Transportation	709	533	176	2,053	1,548	505
	50,851	46,342	4,509	160,633	144,589	16,044
Firm Storage Service	17,131	17,405	(274)	52,787	53,067	(280)
Interruptible Storage Service	7	1	6	10	1	9
Other	546	1,015	(469)	2,862	3,456	(594)
	$68,535	$64,763	$3,772	$216,292	$201,113	$15,179

Pipeline and Storage Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2014	2013	Increase (Decrease)	2014	2013	Increase (Decrease)
Firm Transportation	158,619	129,021	29,598	575,253	427,209	148,044
Interruptible Transportation	998	540	458	3,778	2,506	1,272
	159,617	129,561	30,056	579,031	429,715	149,316

2014 Compared with 2013

Operating revenues for the Pipeline and Storage segment increased $3.8 million for the quarter ended June 30, 2014 as compared with the quarter ended June 30, 2013. The increase was primarily due to an increase in transportation revenues of $4.5 million. The increase in transportation revenues was largely due to additional non-expansion revenue as a result of new short-term contracts for both Empire and Supply Corporation and new contracts for transportation service from an Open Season Supply Corporation held near the end of fiscal 2013. Also contributing to the increase in transportation revenues was additional demand charges associated with the full ramp-up of a transportation contract for an anchor shipper on Empire's Tioga County Extension Project as well as additional commodity charges associated with that contract as a result of higher throughput flowing through a secondary receipt point.

Operating revenues for the Pipeline and Storage segment increased $15.2 million for the nine months ended June 30, 2014 as compared with the nine months ended June 30, 2013. The increase was primarily due to an increase in transportation revenues of $16.0 million. The increase in transportation revenues was largely due to demand and commodity charges on new contracts for transportation service on Supply Corporation's Northern Access expansion project, which was placed fully in service in January 2013 and Supply Corporation's Line N 2012 Expansion Project, which was placed fully in service in November 2012. In addition, the increase in transportation revenues was due to additional demand charges associated with the full-ramp up of a transportation contract for an anchor shipper on Empire's Tioga County Extension Project as well as additional commodity charges associated with that contract due to higher throughput flowing through a secondary receipt point. These projects provide pipeline capacity for Marcellus Shale production. Also contributing to the increase in transportation revenues was additional non-expansion

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revenue as a result of new short-term contracts for both Empire and Supply Corporation and new contracts for transportation service from an Open Season Supply Corporation held near the end of fiscal 2013.

Transportation volume for the quarter ended June 30, 2014 increased by 30.1 Bcf from the prior year's quarter. For the nine months ended June 30, 2014, transportation volume increased by 149.3 Bcf from the prior year's nine-month period. The large increase in transportation volume for the quarter and nine-month periods primarily reflects the impact of the above mentioned expansion projects being placed in service and new contracts for transportation service. For the nine months ended June 30, 2014, the increase was enhanced by weather that was significantly colder than the prior year and colder than normal.

The Pipeline and Storage segment's earnings for the quarter ended June 30, 2014 were $17.9 million, an increase of $3.8 million when compared with earnings of $14.1 million for the quarter ended June 30, 2013. The increase in earnings is primarily due to the earnings impact of higher transportation revenues of $2.9 million, as discussed above, combined with a decrease in operating expenses ($1.4 million). The decrease in operating expenses primarily reflects lower pension and other post-retirement benefit costs. These earnings increases were partially offset by an increase in property taxes of $0.3 million due to the addition of new plant.

The Pipeline and Storage segment's earnings for the nine months ended June 30, 2014 were $58.4 million, an increase of $10.6 million when compared with earnings of $47.8 million for the nine months ended June 30, 2013. The increase in earnings is primarily due to the earnings impact of higher transportation revenues of $10.4 million, as discussed above, combined with a decrease in operating expenses ($4.1 million). The decrease in operating expenses primarily reflects lower pension and other post-retirement benefit costs offset partially by higher compressor station maintenance costs and pipeline integrity program expenses. These earnings increases were partially offset by a decrease in the allowance for funds used during construction (equity component) of $1.1 million, higher income taxes ($0.7 million), an increase in depreciation expense ($0.7 million), higher property taxes ($0.7 million) and higher interest expense ($0.3 million). 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 combined with a reduced benefit associated with the allowance for funds used during construction. The increase in depreciation expense is attributable to incremental depreciation expense related to the projects that were placed in service within the last year. The increase in property taxes is primarily due to the addition of new plant. The increase in interest expense is primarily the result of a decrease in allowance for funds used during construction (borrowed funds component).

Gathering

Gathering Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2014	2013	Increase (Decrease)	2014	2013	Increase (Decrease)
Gathering	$18,740	$10,244	$8,496	$48,541	$23,622	$24,919
Processing and Other Revenues	343	342	1	772	868	(96)
	$19,083	$10,586	$8,497	$49,313	$24,490	$24,823

Gathering Volume

Three Months Ended June 30,	Nine Months Ended June 30,

	2014	2013	Increase (Decrease)	2014	2013	Increase (Decrease)
Gathered Volume - (MMcf)	35,272	28,041	7,231	97,240	66,770	30,470

2014 Compared with 2013

Operating revenues for the Gathering segment increased $8.5 million for the quarter ended June 30, 2014 as compared with the quarter ended June 30, 2013. This increase was largely due to an increase in gathering revenues driven by a 7.2 Bcf increase in gathered volume combined with higher gathering rates (largely in Midstream Corporation's Trout Run Gathering System (Trout Run)). The overall increase in gathered volume was primarily due to an 8.2 Bcf increase in gathered volume on Trout Run.

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In addition, there were increases in gathered volume for Midstream Corporation's Mt. Jewett Gathering System (Mt. Jewett), Midstream Corporation's Owls Nest Gathering System (Owls Nest) and Midstream Corporation's Tionesta Gathering System (Tionesta). These were partially offset by a decrease in gathered volume on Midstream Corporation's Covington Gathering System (Covington). Trout Run, Covington, Mt. Jewett, Owls Nest and Tionesta provide gathering services for Seneca's production. Mt. Jewett, Tionesta and Owls Nest were placed in service in September 2013, April 2013 and February 2014, respectively.

Operating revenues for the Gathering segment increased $24.8 million for the nine months ended June 30, 2014 as compared with the nine months ended June 30, 2013. This increase was largely due to an increase in gathering revenues driven by a 30.5 Bcf increase in gathered volume (due to an increase in gathered volume on Trout Run) combined with higher gathering rates (largely in Trout Run).

The Gathering segment's earnings for the quarter ended June 30, 2014 were $8.7 million, an increase of $4.3 million when compared with earnings of $4.4 million for the quarter ended June 30, 2013. The increase in earnings is mainly due to the earnings impact of higher gathering and processing revenues ($5.5 million) and lower interest expense ($0.3 million). This was partially offset by higher income tax expense ($0.8 million), higher depreciation expense ($0.3 million) and higher operating expense ($0.4 million). The significant growth of Trout Run is primarily responsible for the revenue, depreciation expense and operating expense variations. The increase in income tax expense was largely due to higher state taxes. The decrease in interest expense is largely due to an increase in capitalized interest.

The Gathering segment's earnings for the nine months ended June 30, 2014 were $22.2 million, an increase of $12.8 million when compared with earnings of $9.4 million for the nine months ended June 30, 2013. The increase in earnings is mainly due to the earnings impact of higher gathering and processing revenues ($16.1 million) and lower interest expense ($0.3 million). This was partially offset by higher income tax expense ($2.1 million), higher depreciation expense ($0.8 million) and higher operating expense ($0.9 million). The significant growth of Trout Run is primarily responsible for the revenue, depreciation expense and operating expense variations. The increase in income tax expense was largely due to higher state taxes. The decrease in interest expense is largely due to an increase in capitalized interest.

Utility

Utility Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2014	2013	Increase (Decrease)	2014	2013	Increase (Decrease)
Retail Sales Revenues:						
Residential	$101,136	$101,903	$(767)	$536,527	$456,409	$80,118
Commercial	13,204	11,827	1,377	72,535	60,179	12,356
Industrial	510	951	(441)	3,390	5,178	(1,788)
	114,850	114,681	169	612,452	521,766	90,686
Transportation	28,109	28,261	(152)	129,718	114,974	14,744
Off-System Sales	1,938	—	1,938	19,049	25,020	(5,971)
Other	2,517	1,620	897	7,207	5,463	1,744
	$147,414	$144,562	$2,852	$768,426	$667,223	$101,203

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Utility Throughput

(MMcf)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Increase (Decrease)	Nine Months Ended June 30, 2014	Nine Months Ended June 30, 2013	Increase (Decrease)
Retail Sales:						
Residential	8,826	8,600	226	56,473	49,124	7,349
Commercial	1,238	1,187	51	8,357	7,025	1,332
Industrial	(12)	113	(125)	377	820	(443)
	10,052	9,900	152	65,207	56,969	8,238
Transportation	14,841	13,282	1,559	70,188	59,536	10,652
Off-System Sales	525	—	525	4,335	6,716	(2,381)
	25,418	23,182	2,236	139,730	123,221	16,509

Degree Days

Three Months Ended June 30,	Normal	2014	2013	Percent Colder (Warmer) Than Normal[1]	Percent Colder (Warmer) Than Prior Year[1]
Buffalo	912	841	790	(7.8)%	6.5%
Erie	871	797	791	(8.5)%	0.8%
Nine Months Ended June 30,					
Buffalo	6,455	6,957	5,971	7.8%	16.5%
Erie	6,023	6,625	5,756	10.0%	15.1%

(1) Percents compare actual 2014 degree days to normal degree days and actual 2014 degree days to actual 2013 degree days.

2014 Compared with 2013

Operating revenues for the Utility segment increased $2.9 million for the quarter ended June 30, 2014 as compared with the quarter ended June 30, 2013. This increase was largely due to higher off-system gas sales revenue of $1.9 million (due to higher volumes). Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal. In addition, there was an increase in other revenues of $0.9 million (largely due to an increase in late fees and capacity release revenues).

Operating revenues for the Utility segment increased $101.2 million for the nine months ended June 30, 2014 as compared with the nine months ended June 30, 2013. This increase resulted from a $90.7 million increase in retail gas sales revenue and a $14.7 million increase in transportation revenue. The increase in retail gas sales revenue was primarily due to the impact of an 8.2 Bcf increase in retail throughput coupled with an increase in the price of gas sold period over period. The increase in retail throughput was largely the result of colder weather compared to the prior period. The increase in transportation revenue was primarily due to a 10.7 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. This was partially offset by lower off-system gas sales revenue of $6.0 million (due to lower volumes). The decrease in off-system sales volumes was due to the Utility segment's greater utilization of pipeline capacity in order to reliably meet the increased demand brought on by colder weather experienced during the winter of 2014 as compared to the winter of 2013. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal.

The Utility segment's earnings for the quarter ended June 30, 2014 were $4.8 million, a decrease of $2.8 million when compared with earnings of $7.6 million for the quarter ended June 30, 2013. The decrease in earnings is due to higher operating expenses of $1.7 million and a $0.8 million increase in income tax expense. The increase in operating expenses was largely attributable to increased costs associated with defined benefit and defined contribution retirement plans as a result of a recent settlement with the NYPSC and an increase in bad debt expense. The increase in income tax expense is largely attributable to provision to return adjustments, which led to a larger increase in income tax expense for the quarter ended June 30, 2014 compared to the quarter ended June 30, 2013.

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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, 2014, the WNC reduced earnings by approximately $0.2 million, as the weather was colder than normal during April and May 2014. For the quarter ended June 30, 2013, the WNC preserved earnings of approximately $0.4 million, as the weather was warmer than normal.

The Utility segment's earnings for the nine months ended June 30, 2014 were $64.6 million, a decrease of $0.4 million when compared with earnings of $65.0 million for the nine months ended June 30, 2013. The decrease in earnings was attributable to higher income taxes of $2.4 million (due to a favorable tax settlement in 2013 that did not recur in 2014 and an increase in income taxes due to larger provision to return adjustments recorded in 2014 than in 2013) and higher operating expenses of $5.4 million. The increase in operating expenses was largely attributable to increased costs associated with defined benefit and defined contribution retirement plans as a result of a recent settlement with the NYPSC. These earnings decreases were partially offset by the impact of colder weather in Pennsylvania ($6.8 million). Lower interest expense of $0.9 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 of the Company's $250 million of notes that matured in March 2013.

For the nine months ended June 30, 2014, the WNC reduced earnings by approximately $3.0 million, as the weather was colder than normal. For the nine months ended June 30, 2013, the WNC preserved earnings of approximately $2.1 million, as the weather was warmer than normal.

Energy Marketing

Energy Marketing Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2014	2013	Increase (Decrease)	2014	2013	Increase (Decrease)
Natural Gas (after Hedging)	$46,415	$59,565	$(13,150)	$244,230	$183,330	$60,900
Other	—	9	(9)	43	32	11
	$46,415	$59,574	$(13,159)	$244,273	$183,362	$60,911

Energy Marketing Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2014	2013	Increase (Decrease)	2014	2013	Increase (Decrease)
Natural Gas – (MMcf)	8,930	12,508	(3,578)	45,848	40,266	5,582

2014 Compared with 2013

Operating revenues for the Energy Marketing segment decreased $13.2 million for the quarter ended June 30, 2014 as compared with the quarter ended June 30, 2013. Effective with the first quarter of 2014, the Energy Marketing segment began recording unbilled revenue. The impact of this change for the quarter ended June 30, 2014 was to decrease operating revenues by $24.0 million and decrease volume by 3,975 MMcf. Excluding the impact of unbilled revenue, gas sales revenue benefited from a higher average price of natural gas period over period and an increase in volume sold to retail customers as a result of colder weather.

Operating revenues for the Energy Marketing segment increased $60.9 million for the nine months ended June 30, 2014 as compared with the nine months ended June 30, 2013. The increase reflects an increase in gas sales revenue due to a higher average price of natural gas period over period and an increase in volume sold to retail customers as a result of colder weather. Operating revenues for the nine months ended June 30, 2014 include a $9.7 million accrual for unbilled revenue while operating revenues for the nine months ended June 30, 2013 do not include such an accrual. The volume associated with unbilled revenue at June 30, 2014 was 1,992 MMcf.

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The Energy Marketing segment's earnings for the quarter ended June 30, 2014 were $0.6 million, a decrease of $0.4 million when compared with earnings of $1.0 million for the quarter ended June 30, 2013. The decrease in earnings was largely attributable to lower margin of $0.3 million, which primarily reflects the impact associated with recording unbilled revenues and related gas costs at June 30, 2014. The Energy Marketing segment's earnings for the nine months ended June 30, 2014 were $6.0 million, an increase of $0.3 million when compared with earnings of $5.7 million for the nine months ended June 30, 2013. The increase in earnings was largely attributable to higher margin of $0.4 million, which primarily reflects the impact associated with recording unbilled revenues and related gas costs at June 30, 2014. The Energy Marketing segment experienced a positive impact on margin from the increase in volume sold to retail customers due to the colder weather during the quarter and nine months ended June 30, 2014. However, this was offset by a decline in the benefit the Energy Marketing segment realized from its contracts for storage capacity.

Energy Marketing segment revenues and related purchased gas costs in prior year periods were recorded when billed, resulting in a one month lag. Effective with the first quarter of 2014, the Energy Marketing segment began recording unbilled revenue and related gas costs. The impact of this change for the quarter ended June 30, 2014 was to decrease operating revenues and margin by $24.0 million and $0.5 million, respectively. The impact of this change for the nine months ended June 30, 2014 was to increase operating revenues and margin by $9.7 million and $0.3 million, respectively. Management has determined that the impact of not recording unbilled revenue and related gas costs was immaterial in all prior periods.

Corporate and All Other

2014 Compared with 2013

Corporate and All Other operations recorded earnings of less than $0.1 million for the quarter ended June 30, 2014, an increase of $0.3 million when compared with a loss of $0.3 million for the quarter ended June 30, 2013. Earnings primarily increased as a result of a $0.5 million decrease in operating expenses (due to a reduction in personnel costs) and lower property and other taxes of $0.3 million (due largely to a reduction in capital stock tax). These earnings increases were partially offset by a $0.3 million decrease in margin from the sale of standing timber in Seneca's land and timber division.

For the nine months ended June 30, 2014, Corporate and All Other operations had earnings of $2.9 million, an increase of $4.9 million when compared with a loss of $2.0 million for the nine months ended June 30, 2013. Earnings increased primarily as a result of a $3.6 million death benefit gain on life insurance policies that were recorded during the quarter ended March 31, 2014, which is recorded in Other Income. A $0.7 million increase in margin from the sale of standing timber (including the sale of certain timber stumpage tracts by Seneca's land and timber division) further increased earnings. In addition, earnings were increased by the impact of lower property and other taxes of $0.6 million (due to a reduction in capital stock tax), an increase in income from unconsolidated subsidiaries of $0.3 million (due to the sale of turbine assets held by Horizon Power's investment in Energy Systems North East, LLC), and a $0.4 million increase in other revenues (largely due to the receipt of settlement proceeds on former insurance policies). These earnings increases were partially offset by a $0.5 million increase in operating expenses (due to higher personnel costs).

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

Interest on long-term debt decreased $0.9 million for the quarter ended June 30, 2014 as compared with the quarter ended June 30, 2013. The decrease in interest on long-term debt was due to an increase in capitalized interest (mostly in Midstream Corporation) for the quarter ended June 30, 2014 compared to the quarter ended June 30, 2013. For the nine months ended June 30, 2014, interest on long-term debt increased $0.5 million as compared with the nine months ended June 30, 2013. 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. This was partially offset by the impact of higher capitalized interest (mostly Midstream Corporation) during fiscal 2014 compared to fiscal 2013.

CAPITAL RESOURCES AND LIQUIDITY

The Company’s primary source of cash during the nine-month period ended June 30, 2014 consisted of cash provided by operating activities. 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. These sources of cash were supplemented by net proceeds from the issuance of common stock for both the nine months ended June 30, 2014 and June 30, 2013, including the issuance of original issue shares for the Direct Stock Purchase and Dividend Reinvestment Plan. For the nine months ended June 30, 2014, net proceeds from the issuance of common stock also includes the issuance of original issue shares for the Company’s

401(k) plans. During the nine months ended June 30, 2013, 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 $725.6 million for the nine months ended June 30, 2014, an increase of $138.4 million compared with $587.2 million provided by operating activities for the nine months ended June 30, 2013. The increase in cash provided by operating activities reflects higher cash provided by operating activities in the Exploration and Production segment, Utility segment, and Corporate category. The increase in the Exploration and Production segment is primarily due to higher cash receipts from natural gas production in the Appalachian region. The increase in the Utility segment is primarily due to the timing of gas cost recovery. Lastly, the increase in the Corporate category is primarily due to the receipt of life insurance proceeds.

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Investing Cash Flow

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets totaled $664.0 million during the nine months ended June 30, 2014 and $504.5 million for the nine months ended June 30, 2013. 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:

Total Expenditures for Long-Lived Assets

Nine Months Ended June 30, (Millions)	2014		2013		Increase(Decrease)	
Exploration and Production:						
Capital Expenditures	$444.4	(1)	$385.0	(2)	$ 59.4	
Pipeline and Storage:						
Capital Expenditures	64.9	(1)	41.0	(2)	23.9	
Gathering:						
Capital Expenditures	93.2	(1)	34.8	(2)	58.4	
Utility:						
Capital Expenditures	60.9	(1)	43.0	(2)	17.9	
All Other:						
Capital Expenditures	0.6	(1)	0.7	(2)	(0.1	)
	$664.0		$504.5		$ 159.5	

(1) At June 30, 2014, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $101.3 million, $13.4 million, $16.3 million and $4.7 million, respectively, of accounts payable and accrued liabilities related to capital expenditures. At September 30, 2013, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $58.5 million, $5.6 million, $6.7 million and $10.3 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

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

Exploration and Production

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2014 were primarily well drilling and completion expenditures and included approximately $381.9 million for the Appalachian region (including $368.0 million in the Marcellus Shale area) and $62.5 million for the West Coast region. These amounts included approximately $145.1 million spent to develop proved undeveloped reserves.

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.

Pipeline and Storage

The Pipeline and Storage capital expenditures for the nine months ended June 30, 2014 were mainly related to additions, improvements and replacements to this segment’s transmission and gas storage systems and also include $17.3 million spent on the Mercer Expansion Project. The majority of the Pipeline and Storage capital expenditures for the nine months ended June 30, 2013 were 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). The Pipeline and Storage capital expenditures for the nine months ended June 30, 2013 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, 2014, the total amount reserved for the Pipeline and Storage segment's preliminary survey and investigation costs was $8.1 million.

Supply Corporation and Empire are moving forward with, or have recently completed, 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.

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 ("TGP") at Mercer, Pennsylvania, a pooling point recently established at Tennessee's Station 219 ("Mercer Expansion Project"). Supply Corporation has executed a precedent agreement with Range Resources for 105,000 Dth per day, all of the project capacity, for service expected to begin November 2014. The cost estimate is $33.6 million, of which $29.6 million is for expansion and $4.0 million is for system modernization. Supply Corporation has received authorization to construct the required approximately 3,550 horsepower of compression at Mercer, and replace 2.08 miles of 24" pipeline, all under its FERC blanket certificate authorization. Construction began in February of 2014. As of June 30, 2014, approximately $18.0 million has been spent on the Mercer Expansion Project, all of which has been capitalized as Construction Work in Progress.

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 Texas Eastern Transmission, LP ("TETCO") at Holbrook and TGP at Mercer ("Westside Expansion and Modernization Project"). Supply Corporation executed two precedent agreements for all 175,000 Dth per day of project capacity, for service expected to begin in 2015. The Westside Expansion and Modernization Project facilities are expected to include the replacement of approximately 23.3 miles of 20" pipe with 24" pipe and the addition of approximately 3,550 horsepower of compression at Mercer. The preliminary cost estimate is $76.2 million, of which $39.6 million is related to expansion and the remainder is for replacement. Supply Corporation filed the FERC 7(c) application in early February 2014. Approximately $1.4 million has been spent to study the Westside Expansion and Modernization Project through June 30, 2014. The Company has determined it is highly probable that the project will be built. Accordingly, previous reserves have been reversed and the project costs have been reestablished as a Deferred Charge on the Consolidated Balance Sheet.

Supply Corporation and TGP have jointly developed a project that will combine expansions on both pipeline systems, providing a seamless transportation path from TGP's 300 Line in the Marcellus fairway to the TransCanada Pipeline delivery point at Niagara. Supply Corporation has offered 140,000 Dth per day of capacity on its system to TGP under a lease, from its Ellisburg Station for redelivery to TGP in East Eden, New York ("Northern Access 2015"). The project will provide Seneca Resources, TGP's anchor shipper, with an outlet to premium Dawn indexed markets in Canada, for their Clermont Area Marcellus production. The Northern Access 2015 project involves the construction of a new 15,400 horsepower compressor station in Hinsdale, New York and a 7,700 horsepower addition to its compressor station in Concord, New York, for service expected to commence in late 2015. Supply Corporation and TGP have executed a precedent agreement incorporating the lease agreement, and both companies filed their respective FERC 7(c) applications in early March 2014. The preliminary cost estimate for the Northern Access 2015 project is $66 million. Approximately $0.9 million has been spent to study the Northern Access 2015 project through June 30, 2014. The Company has determined it is highly probable that the project will be built. Accordingly, previous reserves have been reversed and the project costs have been reestablished as a Deferred Charge on the Consolidated Balance Sheet.

Supply Corporation and Empire have been working with Seneca Resources to develop a project which would move significant prospective Marcellus production from its Western Development Area at Clermont to an interconnection on Empire with TransCanada Pipeline at Chippawa (“Northern Access 2016”). Similar to the Northern Access 2015 project, this project would provide an outlet to premium Dawn indexed markets in Canada in late 2016. The Northern Access 2016 project involves the construction of approximately 101 miles of 24” pipeline and 18,000 horsepower of compression on the two systems. The preliminary cost estimate for the Northern Access 2016 project is $410 million. Seneca Resources executed anchor shipper agreements for 350,000 Dth per day of firm transportation delivery capacity to Chippawa on this project, and has been awarded the capacity by Supply Corporation and Empire following the close of their respective Open Seasons on June 26, 2014. On July 10, 2014, Supply Corporation and Empire initiated the FERC NEPA Pre-filing process on this project. As of June 30, 2014, approximately $0.6 million has been spent to study the Northern Access 2016 project, all of which has been included in preliminary survey and investigation charges and has been fully reserved for at June 30, 2014.

On August 12, 2013, Empire concluded an Open Season, offering for the first time no-notice transportation and storage services to new and existing shippers on the Empire pipeline system. Rochester Gas & Electric ("RG&E"), Empire's largest LDC connected market, has executed a precedent agreement to convert all 172,500 Dth per day of its standard firm transportation services to no-notice service, including 3.3 Bcf of no-notice storage service. The new services will provide RG&E with a superior flexible delivery service with daily and seasonal load balancing capabilities and greater access to Marcellus supplies. In addition, Empire has executed a precedent agreement with New York State Electric and Gas for 14,816 Dth per day of transportation capacity and a third agreement with Distribution Corporation for the remaining 34,500 Dth per day of project capacity, providing both LDCs with increased access to Marcellus supplies. The project would require Empire to construct a 17.2 mile, 12" pipeline and interconnection between Empire's pipeline system and Supply Corporation's system at Tuscarora, New York. It would also require Empire to modify its Oakfield compressor station and require Supply Corporation to construct approximately 1,380 horsepower of compression at its Tuscarora compressor station ("Tuscarora Lateral Project"). Supply Corporation concluded an Open Season and has awarded to Empire the necessary storage services under a lease agreement. Empire and Supply Corporation began the FERC pre-filing process on April 12, 2013, and both companies filed their FERC 7(c) applications in March 2014. The preliminary cost estimate for the Tuscarora Lateral Project is $45.2 million. Approximately $1.6 million has been spent to study the Tuscarora Lateral Project through June 30, 2014. The Company has determined it is highly probable that the project will be built. Accordingly, previous reserves have been reversed and the project costs have been reestablished as a Deferred Charge on the Consolidated Balance Sheet.

Empire is developing an expansion of its system that would allow for the transportation of approximately 250,000 Dth per day of additional Marcellus supplies from Tioga County, Pennsylvania, to TransCanada Pipeline and the TGP 200 Line ("Central Tioga County Extension"). The connection to Supply Corporation afforded by the Tuscarora Lateral Project could allow those Marcellus supplies to be sourced on other parts of the Supply Corporation system in addition to Tioga County. Such a configuration would likely involve facility investments on the Supply Corporation system as well. The preliminary cost estimate for the Central Tioga County Extension is $150 million. As of June 30, 2014, approximately $0.2 million has been spent to study the Central Tioga County Extension project, all of which has been included in preliminary survey and investigation charges and has been fully reserved for at June 30, 2014.

Gathering

The majority of the Gathering segment capital expenditures for the nine months ended June 30, 2014 were for the construction of Midstream Corporation's Clermont Gathering System and to build compressor stations on Midstream Corporation's Trout Run Gathering System, as discussed below. The majority of the Gathering segment capital expenditures for the nine months ended June 30, 2013 were for the expansion of Midstream Corporation's Trout Run Gathering System.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, continues to develop its Trout Run Gathering System in Lycoming County, Pennsylvania. The Trout Run Gathering System was initially placed in service in May 2012. The current system consists of approximately 40 miles of backbone and in-field gathering pipelines and two compressor stations. As of June 30, 2014, the Company has spent approximately $153.1

million in costs related to this project, including approximately $25.1 million spent during the nine months ended June 30, 2014, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2014.

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, 2014, the Company has spent approximately $32.7 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, 2014.

NFG Midstream Clermont, LLC, a wholly owned subsidiary of Midstream Corporation, is building an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. The preliminary cost estimate for the initial buildout is anticipated to be in the range of $150 million to $250 million. As of June 30, 2014, approximately $60.5 million has been spent on the Clermont Gathering System, including approximately $57.2 million spent during the nine months ended June 30, 2014, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2014.

Midstream Corporation has built and currently operates, or is planning the construction of, other gathering systems. As of June 30, 2014, the Company has spent approximately $9.5 million in costs related to these projects, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2014.

Utility

The majority of the Utility capital expenditures for the nine months ended June 30, 2014 and June 30, 2013 were made for replacement of mains and main extensions, as well as for the replacement of service lines. The capital expenditures for the nine months ended June 30, 2014 also include $13.0 million related to the planned replacement of the Utility segment's legacy mainframe systems.

Project Funding

The Company has been financing the Pipeline and Storage segment and Gathering segment projects mentioned above, as well as the Exploration and Production segment capital expenditures, with cash from operations and both short and long-term borrowings. 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 as necessary during fiscal 2014. The Company anticipates that it will issue long-term debt during fiscal 2015 to help meet its capital expenditure needs. The level of such short-term and long-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 did not change when comparing the balance sheet at June 30, 2014 to the balance sheet at September 30, 2013. The maximum amount of short-term debt outstanding during the nine months ended June 30, 2014 was $46.7 million. While the Company did not have any outstanding commercial paper and short-term notes payable to banks at June 30, 2014, the Company continues to consider short-term debt 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, 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.

The Company maintains a $750.0 million syndicated committed credit facility, which commitment extends through January 6, 2017. The Company also has a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under the uncommitted lines of credit are made at competitive market rates. The uncommitted credit lines 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 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, 2014, the commercial paper program was backed by the $750.0 million syndicated committed credit facility. 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, 2014, the Company's debt to capitalization ratio (as calculated under the facility) was .41. The constraints specified in the committed credit facility would have permitted an additional $2.69 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.

The Company's $750.0 million committed credit facility 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, 2014, the Company did not have any debt outstanding under the committed credit facility.

Under the Company's existing indenture covenants, at June 30, 2014, the Company would have been permitted to issue up to a maximum of $1.82 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.

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, 2014) 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 embedded cost of long-term debt was 5.58% at both June 30, 2014 and June 30, 2013.

None of the Company's long-term debt at June 30, 2014 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 both 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.

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 $35.6 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.

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During the nine months ended June 30, 2014, the Company contributed $30.0 million to its Retirement Plan and $2.0 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2014, the Company expects its contributions to the Retirement Plan to be in the range of zero to $5.0 million. 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 2014 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 2014, the Company expects to make no further contributions to its VEBA trusts and 401(h) accounts.

In January 2014, Seneca entered into a precedent agreement with Transcontinental Pipe Line Company, LLC (Transcontinental) whereby Transcontinental will provide 189,405 Dth per day of firm natural gas transportation service to Seneca on Transcontinental's proposed Atlantic Sunrise Project. The proposed Atlantic Sunrise Project involves the construction of approximately 120 miles of new natural gas pipeline extending from Transcontinental's Leidy Line in Columbia County, Pennsylvania to an interconnection with Transcontinental's mainline in Lancaster County, Pennsylvania. The targeted in-service date for the proposed pipeline facilities is September 2017.

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. Among other things, the Dodd-Frank Act (1) regulates certain participants in the swaps markets, including new entities defined as "swap dealers" and "major swap participants," (2) requires clearing and exchange-trading of certain swaps that the CFTC determines must be cleared, (3) requires reporting and recordkeeping of swaps, and (4) enhances the CFTC's enforcement authority, including the authority to establish position limits on derivatives and increases penalties for violations of the Commodity Exchange Act. 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 costs through higher transaction costs and 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 certain 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 Dodd-Frank Act may also increase costs for derivative recordkeeping, reporting, documentation, position limit compliance, and other compliance; cause parties to materially alter the terms of derivative contracts; cause parties to restructure certain derivative contracts; reduce the availability of derivatives to protect against risks that the Company encounters or to optimize assets; reduce the Company's ability to monetize or restructure existing derivative contracts; and increase the Company's exposure to less creditworthy counterparties, all of which could increase the Company's business costs. 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. 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 $2.9 million at June 30, 2014 and represent 2.2% of the Total Net Assets shown in Part I, Item 1 at Note 2 – Fair Value Measurements at June 30, 2014.

The decrease in the net fair value liability of the Level 3 positions from October 1, 2013 to June 30, 2014, as shown in Part I, Item 1 at Note 2, was attributable to a decrease in the commodity price of crude oil (at the aforementioned sales location) 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, 2014.

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, 2014, 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 2013 Form 10-K. There have been no subsequent material changes to the Company’s exposure to market risk sensitive instruments.

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.” Although neither division has a rate case on file, see below for a description of other rate proceedings affecting the New York division. 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 informal discussions, 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 stated, among other things, that there was an “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. Discussions for settlement of Distribution Corporation’s rates and charges were commenced while the formal case to establish permanent rates proceeded along a parallel path.

On December 6, 2013, Distribution Corporation filed an agreement, executed by five of the six active parties in the rate proceeding, for settlement of the temporary rate proceeding and all issues relating to rates. The settlement extends customer rates at the levels previously established in 2007 for a minimum two-year term retroactive to

October 1, 2013. Although customer rates were not changed, the parties agreed that the allowed rate of return on equity would be set, for ratemaking purposes, at 9.1%. Following conventional practice in New York, the agreement authorizes an "earnings sharing mechanism" ("ESM"). The ESM distributes earnings above the allowed rate of return as follows: from 9.5% to 10.5%, 50% would be allocated to shareholders, and 50% will be deferred for the benefit of customers; above 10.5%, 20% to shareholders and 80% will be deferred for the benefit of customers. The agreement further authorizes, and rates reflect, an increase in Distribution Corporation's pipeline replacement spending by $8.2 million per year. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. The Consolidated Balance Sheet at September 30, 2013 reflected a $7.5 million ($4.9 million after-tax) refund provision related to the settlement agreement. This amount has been passed back to ratepayers as of June 30, 2014.

The NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014.

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.

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.

At June 30, 2014, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be approximately $14.2 million. The Company expects to recover such environmental clean-up costs through rate recovery.

The Company's estimated liability for clean-up costs discussed above includes a $12.8 million estimated liability 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.

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 May 2014, the FASB issued authoritative guidance regarding revenue recognition. The authoritative guidance provides a single, comprehensive revenue recognition model for all contracts with customers to improve comparability. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2018 and early adoption is not permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements and disclosures.

In June 2014, the FASB issued authoritative guidance regarding accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the employee has completed the requisite service period. This authoritative guidance requires that such performance targets that affect vesting be treated as performance conditions, meaning that the performance target should not be factored in the calculation of the award at the grant date. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2017, with early adoption permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements.

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.

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

3. 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;
4. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;
5. Changes in the price of natural gas or oil;

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6. Changes in price differentials between similar quantities of natural gas or oil sold at different geographic locations, and the effect of such changes on commodity production, revenues and demand for pipeline transportation capacity to or from such locations;
7. Other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date;
8. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;
9. Uncertainty of oil and gas reserve estimates;
10. Significant differences between the Company's projected and actual production levels for natural gas or oil;
11. 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;
12. Changes in demographic patterns and weather conditions;
13. Changes in the availability, price or accounting treatment of derivative financial instruments;
14. 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;
15. 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;
16. The creditworthiness or performance of the Company's key suppliers, customers and counterparties;
17. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;
18. Significant differences between the Company's projected and actual capital expenditures and operating expenses;
19. 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;
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

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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, 2014.

Changes in Internal Control Over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended June 30, 2014 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.

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 2013 Form 10-K have not materially changed.

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

On April 1, 2014, the Company issued a total of 3,850 unregistered shares of Company common stock to the seven 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, 2014. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

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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, 2014	737	$69.51	—	6,971,019
May 1 - 31, 2014	17,487	$74.56	—	6,971,019
June 1 - 30, 2014	9,872	$75.48	—	6,971,019
Total	28,096	$74.75	—	6,971,019

(a) Represents shares of common stock of the Company tendered to the Company by holders of stock options, SARs, restricted stock units or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the quarter ended June 30, 2014, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program.

(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.

Item 6. Exhibits

Exhibit Number	Description of Exhibit
•	National Fuel Gas Company By-Laws as amended June 12, 2014 (Exhibit 3.1, Form 8-K dated June 16, 2014).
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Twelve Months Ended June 30, 2014 and the Fiscal Years Ended September 30, 2010 through 2013.
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, 2014 and 2013.
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, 2014 and 2013, (ii) the Consolidated Statements of Comprehensive Income for the three and nine months ended June 30, 2014 and 2013, (iii) the Consolidated Balance Sheets

at June 30, 2014 and September 30, 2013, (iv) the Consolidated Statements of Cash Flows for the nine months ended June 30, 2014 and 2013 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 8, 2014