NATIONAL FUEL GAS CO
Form 10-Q
August 07, 2015
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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, 2015
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, 2015: 84,566,550 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.
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	
2014 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2014
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.
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

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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.
Precedent Agreement	An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called “conditions precedent”) happen, usually within a specified time.

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Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped (PUD) reserves	Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make these reserves productive.
Reserves	The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
Revenue decoupling mechanism	A rate mechanism which adjusts customer rates to render a utility financially indifferent to throughput decreases resulting from conservation.
S&P	Standard & Poor's Rating Service
SAR	Stock appreciation right
Service agreement	The binding agreement by which the pipeline company agrees to provide service and the shipper agrees to pay for the service.
Stock acquisitions	Investments in corporations
VEBA	Voluntary Employees' Beneficiary Association
WNC	Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

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• The Company has nothing to report under this item.

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

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Part I. Financial Information

Item 1. Financial Statements
National Fuel Gas Company
Consolidated Statements of Income and Earnings
Reinvested in the Business
(Unaudited)

(Thousands of Dollars, Except Per Common Share Amounts)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Nine Months Ended June 30, 2015	Nine Months Ended June 30, 2014
INCOME				
Operating Revenues	$339,815	$440,144	$1,459,851	$1,746,458
Operating Expenses				
Purchased Gas	27,038	86,628	344,728	577,005
Operation and Maintenance	110,697	107,232	356,525	352,794
Property, Franchise and Other Taxes	22,717	22,483	68,561	69,114
Depreciation, Depletion and Amortization	79,865	96,788	265,298	279,876
Impairment of Oil and Gas Producing Properties	588,712	—	709,060	—
	829,029	313,131	1,744,172	1,278,789
Operating Income (Loss)	(489,214)	127,013	(284,321)	467,669
Other Income (Expense):				
Interest Income	327	370	1,631	1,321
Other Income	2,066	1,496	4,638	6,847
Interest Expense on Long-Term Debt	(22,213)	(22,116)	(66,900)	(67,767)
Other Interest Expense	(1,007)	(1,136)	(3,382)	(3,460)
Income (Loss) Before Income Taxes	(510,041)	105,627	(348,334)	404,610
Income Tax Expense (Benefit)	(216,907)	41,107	(156,610)	162,627
Net Income (Loss) Available for Common Stock	(293,134)	64,520	(191,724)	241,983
EARNINGS REINVESTED IN THE BUSINESS				
Balance at Beginning of Period	1,650,840	1,557,184	1,614,361	1,442,617
	1,357,706	1,621,704	1,422,637	1,684,600
Dividends on Common Stock	(33,388)	(32,373)	(98,319)	(95,269)
Balance at June 30	$1,324,318	$1,589,331	$1,324,318	$1,589,331
Earnings Per Common Share:				
Basic:				
Net Income (Loss) Available for Common Stock	$(3.47)	$0.77	$(2.27)	$2.89
Diluted:				
Net Income (Loss) Available for Common Stock	$(3.44)	$0.76	$(2.25)	$2.85
Weighted Average Common Shares Outstanding:				
Used in Basic Calculation	84,453,602	84,029,124	84,326,182	83,863,764
Used in Diluted Calculation	85,248,281	84,973,100	85,237,514	84,892,473
Dividends Per Common Share:				
Dividends Declared	$0.395	$0.385	$1.165	$1.135

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)	2015	2014	2015	2014
Net Income (Loss) Available for Common Stock	$(293,134)	$64,520	$(191,724)	$241,983
Other Comprehensive Income (Loss), Before Tax:				
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	90	1,191	(56)	4,311
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(9,483)	(13,221)	295,511	(77,903)
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	(50,875)	14,464	(129,270)	30,921
Other Comprehensive Income (Loss), Before Tax	(60,268)	2,450	166,185	(42,655)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	33	420	(27)	1,576
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(4,060)	(7,656)	124,792	(34,968)
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	(21,800)	8,262	(54,807)	15,134
Income Taxes – Net	(25,827)	1,033	69,958	(18,251)
Other Comprehensive Income (Loss)	(34,441)	1,417	96,227	(24,404)
Comprehensive Income (Loss)	$(327,575)	$65,937	$(95,497)	$217,579

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

	June 30, 2015	September 30, 2014
(Thousands of Dollars)		
ASSETS		
Property, Plant and Equipment	$8,937,174	$8,245,791
Less - Accumulated Depreciation, Depletion and Amortization	3,455,446	2,502,700
	5,481,728	5,743,091
Current Assets		
Cash and Temporary Cash Investments	310,031	36,886
Hedging Collateral Deposits	11,101	2,734
Receivables – Net of Allowance for Uncollectible Accounts of $34,226 and $31,811, Respectively	135,427	149,735
Unbilled Revenue	18,234	25,663
Gas Stored Underground	16,506	39,422
Materials and Supplies - at average cost	31,339	27,817
Other Current Assets	49,449	54,752
Deferred Income Taxes	39,383	40,323
	611,470	377,332
Other Assets		
Recoverable Future Taxes	168,436	163,485
Unamortized Debt Expense	17,000	14,304
Other Regulatory Assets	215,630	224,436
Deferred Charges	12,347	14,212
Other Investments	89,027	86,788
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	46,062	36,512
Fair Value of Derivative Financial Instruments	242,320	72,606
Other	172	1,355
	796,470	619,174
Total Assets	$6,889,668	$6,739,597

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

	June 30, 2015	September 30, 2014
(Thousands of Dollars)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued And Outstanding – 84,528,930 Shares and 84,157,220 Shares, Respectively	$84,529	$84,157
Paid in Capital	746,263	716,144
Earnings Reinvested in the Business	1,324,318	1,614,361
Accumulated Other Comprehensive Income (Loss)	92,248	(3,979)
Total Comprehensive Shareholders' Equity	2,247,358	2,410,683
Long-Term Debt, Net of Current Portion	2,099,000	1,649,000
Total Capitalization	4,346,358	4,059,683
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	85,600
Current Portion of Long-Term Debt	—	—
Accounts Payable	137,892	136,674
Amounts Payable to Customers	44,842	33,745
Dividends Payable	33,388	32,400
Interest Payable on Long-Term Debt	18,585	29,960
Customer Advances	44	19,005
Customer Security Deposits	18,329	15,761
Other Accruals and Current Liabilities	157,729	136,672
Fair Value of Derivative Financial Instruments	9,128	759
	419,937	490,576
Deferred Credits		
Deferred Income Taxes	1,328,719	1,456,283
Taxes Refundable to Customers	95,157	91,736
Unamortized Investment Tax Credit	834	1,145
Cost of Removal Regulatory Liability	180,106	173,199
Other Regulatory Liabilities	126,371	81,152
Pension and Other Post-Retirement Liabilities	144,136	134,202
Asset Retirement Obligations	119,644	117,713
Other Deferred Credits	128,406	133,908
	2,123,373	2,189,338
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$6,889,668	$6,739,597

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended June 30,	
(Thousands of Dollars)	2015	2014
OPERATING ACTIVITIES		
Net Income (Loss) Available for Common Stock	$(191,724)	$241,983
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:		
Impairment of Oil and Gas Producing Properties	709,060	—
Depreciation, Depletion and Amortization	265,298	279,876
Deferred Income Taxes	(198,116)	119,395
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(9,064)	(4,641)
Stock-Based Compensation	8,383	12,438
Other	7,329	10,969
Change in:		
Hedging Collateral Deposits	(8,367)	1,094
Receivables and Unbilled Revenue	22,175	(72,082)
Gas Stored Underground and Materials and Supplies	20,259	35,503
Unrecovered Purchased Gas Costs	—	12,408
Other Current Assets	14,367	5,376
Accounts Payable	11,153	26,386
Amounts Payable to Customers	11,097	19,977
Customer Advances	(18,961)	(21,878)
Customer Security Deposits	2,568	(17)
Other Accruals and Current Liabilities	13,794	17,590
Other Assets	1,124	25,449
Other Liabilities	52,261	15,743
Net Cash Provided by Operating Activities	712,636	725,569
INVESTING ACTIVITIES		
Capital Expenditures	(718,965)	(609,427)
Other	(1,065)	4,696
Net Cash Used in Investing Activities	(720,030)	(604,731)
FINANCING ACTIVITIES		
Changes in Notes Payable to Banks and Commercial Paper	(85,600)	—
Excess Tax Benefits Associated with Stock-Based Compensation Awards	9,064	4,641
Net Proceeds from Issuance of Long-Term Debt	445,662	—
Dividends Paid on Common Stock	(97,330)	(94,269)
Net Proceeds from Issuance of Common Stock	8,743	6,585
Net Cash Provided by (Used) in Financing Activities	280,539	(83,043)
Net Increase in Cash and Temporary Cash Investments	273,145	37,795
Cash and Temporary Cash Investments at October 1	36,886	64,858
Cash and Temporary Cash Investments at June 30	$310,031	$102,653

Supplemental Disclosure of Cash Flow Information		
Non-Cash Investing Activities:		
Non-Cash Capital Expenditures	$122,587	$135,747

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.

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, 2014, 2013 and 2012 that are included in the Company's 2014 Form 10-K. The consolidated financial statements for the year ended September 30, 2015 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, 2015 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2015. 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. 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 $32.9 million at June 30, 2015, 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 $177.5 million and $141.7 million at June 30, 2015 and September 30, 2014, respectively. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the

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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. The book value of the oil and gas properties exceeded the ceiling at March 31, 2015 as well as June 30, 2015. As such, the Company recognized pre-tax impairment charges of $588.7 million and $709.1 million for the quarter and nine months ended June 30, 2015, respectively. Deferred income tax benefits of $248.9 million and $299.8 million related to the impairment charges were also recognized for the quarter and nine months ended June 30, 2015, respectively. In adjusting estimated future cash flows for hedging under the ceiling test at March 31, 2015 and June 30, 2015, estimated future net cash flows were increased by $97.0 million and $168.0 million, respectively.

Accumulated Other Comprehensive Income (Loss). The components of Accumulated Other Comprehensive Income (Loss) and changes for the quarter and nine months ended June 30, 2015 and 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, 2015				
Balance at April 1, 2015	$174,413	$8,296	$(56,020)	$126,689
Other Comprehensive Gains and Losses Before Reclassifications	(5,423)	57	—	(5,366)
Amounts Reclassified From Other Comprehensive Income (Loss)	(29,075)	—	—	(29,075)
Balance at June 30, 2015	$139,915	$8,353	$(56,020)	$92,248
Nine Months Ended June 30, 2015				
Balance at October 1, 2014	$43,659	$8,382	$(56,020)	$(3,979)
Other Comprehensive Gains and Losses Before Reclassifications	170,719	(29)	—	170,690
Amounts Reclassified From Other Comprehensive Income (Loss)	(74,463)	—	—	(74,463)
Balance at June 30, 2015	$139,915	$8,353	$(56,020)	$92,248
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 Income (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 Income (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 Income (Loss). The details about the reclassification adjustments out of accumulated other comprehensive income (loss) for the quarter and nine months ended June 30, 2015 and 2014 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Income (Loss) Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss)				Affected Line Item in the Statement Where Net Income (Loss) is Presented
	Three Months Ended June 30,		Nine Months Ended June 30,		
	2015	2014	2015	2014	
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:					
Commodity Contracts	$50,878	($14,547)	$124,386	($27,372)	Operating Revenues
Commodity Contracts	(3)	83	4,884	(3,549)	Purchased Gas
Gains (Losses) on Securities Available for Sale	—	(16)	—	(16)	Other Income
	50,875	(14,480)	129,270	(30,937)	Total Before Income Tax
	(21,800)	8,269	(54,807)	15,141	Income Tax Expense
	$29,075	($6,211)	$74,463	($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, 2015	At September 30, 2014
Prepayments	$11,173	$10,079
Prepaid Property and Other Taxes	11,061	13,743
Federal Income Taxes Receivable	—	8,211
Fair Values of Firm Commitments	11,078	—
Regulatory Assets	16,137	22,719
	$49,449	$54,752

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

	At June 30, 2015	At September 30, 2014
Accrued Capital Expenditures	$76,242	$80,348
Regulatory Liabilities	5,556	18,072
Reserve for Gas Replacement	32,908	—
Federal Income Taxes Payable	13,766	—
State Income Taxes Payable	1,763	5,798
Other	27,494	32,454
	$157,729	$136,672

Earnings Per Common Share. Basic earnings per common share is computed by dividing 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 180,065 and 2,948 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2015, respectively. There were 338 and 829 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2014, respectively.

Stock-Based Compensation. The Company granted 107,044 performance shares during the nine months ended June 30, 2015. The weighted average fair value of such performance shares was $65.26 per share for the nine months ended June 30, 2015. 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, 2015 must meet a performance goal related to relative return on capital over the performance cycle of October 1, 2014 to September 30, 2017. 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, 2015 must meet a performance goal related to relative total shareholder return over the performance cycle of October 1, 2014 to September 30, 2017. 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 total shareholder return performance shares ("TSR 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 the TSR 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 TSR performance shares awarded, the result of which is recorded as compensation expense over the vesting term of the award.

The Company granted 88,899 non-performance based restricted stock units during the nine months ended June 30, 2015. The weighted average fair value of such non-performance based restricted stock units was $64.04 per share for the nine months ended June 30, 2015. 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, 2015.

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. The original effective date of this authoritative guidance was as of the Company's first quarter of fiscal 2018. However, the FASB has delayed the effective date of the new revenue standard by one year, and the guidance will now be effective as of the Company's first quarter of fiscal 2019. 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.

In April 2015, the FASB issued authoritative guidance regarding the presentation of debt issuance costs. The authoritative guidance requires that all costs incurred to issue debt be presented in the balance sheet as a direct deduction from the carrying value of the debt. This authoritative guidance, which will be applied on a retrospective basis, 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 and disclosures.

In July 2015, the FASB issued authoritative guidance simplifying inventory measurement by requiring companies to value inventory at the lower of cost and net realizable value. The authoritative guidance applies to all inventory other than inventory that is measured using last-in, first-out or the retail inventory method. The intention of this authoritative guidance is to eliminate some diversity in practice. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2018, with early adoption permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements.

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, 2015 and September 30, 2014. 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 combines gas and oil swaps 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, 2015				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[(1)]	Total[(1)]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$285,506	$—	$—	$ —	$285,506
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	4,198	—	—	(4,198)	—
Over the Counter Swaps – Gas and Oil	—	240,633	2,594	(907)	242,320
Other Investments:					
Balanced Equity Mutual Fund	36,895	—	—	—	36,895
Common Stock – Financial Services Industry	6,402	—	—	—	6,402
Other Common Stock	523	—	—	—	523
Hedging Collateral Deposits	11,101	—	—	—	11,101
Total	$344,625	$240,633	$2,594	$ (5,105)	$582,747

Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$11,984	$—	$—	$ (4,198)	$7,786
Over the Counter Swaps – Gas and Oil	—	1,572	123	(907)	788
Foreign Currency Contracts	—	554	—	—	554
Total	$11,984	$2,126	$123	$ (5,105)	$9,128
Total Net Assets/(Liabilities)	$332,641	$238,507	$2,471	$ —	$573,619

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Recurring Fair Value Measures	At fair value as of September 30, 2014				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[1]	Total[1]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$23,794	$—	$—	$ —	$23,794
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	2,725	—	—	(1,987)	738
Over the Counter Swaps – Gas and Oil	—	75,951	1,368	(5,451)	71,868
Other Investments:					
Balanced Equity Mutual Fund	35,331	—	—	—	35,331
Common Stock – Financial Services Industry	6,629	—	—	—	6,629
Other Common Stock	455	—	—	—	455
Hedging Collateral Deposits	2,734	—	—	—	2,734
Total	$71,668	$75,951	$1,368	$ (7,438)	$141,549
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$2,674	$—	$—	$ (1,987)	$687
Over the Counter Swaps – Gas and Oil	—	5,523	—	(5,451)	72
Total	$2,674	$5,523	$—	$ (7,438)	$759
Total Net Assets/(Liabilities)	$68,994	$70,428	$1,368	$ —	$140,790

(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, 2015 and September 30, 2014, 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 $11.1 million at June 30, 2015 and $2.7 million at September 30, 2014, 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, 2015 and September 30, 2014 consist of natural gas price swap agreements used in the Company’s Exploration and Production and Energy Marketing segments, the majority of the crude oil price swap agreements used in the Company’s Exploration and Production segment and foreign currency contracts 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 fair value of the Level 2 foreign currency contracts are valued using the market approach based on observable market transactions of forward rates. 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, 2015 and September 30, 2014. 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, 2015, it was assumed that Midway Sunset oil was 92.6% 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 87.8% to 96.7% 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 asset would have been approximately $0.8 million lower at June 30, 2015. 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 asset would have been approximately $0.8 million higher at June 30, 2015. 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, 2015, 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, 2015 and 2014, respectively. For the quarters and nine months ended June 30, 2015 and June 30, 2014, 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, 2015	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, 2015
Derivative Financial Instruments[2]	$4,826	$(2,249)[1]	$(106)	$—	$2,471

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended June 30, 2015.
(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, 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, 2015
Derivative Financial Instruments[2]	$1,368	$(9,053)[1]	$10,156	$—	$2,471

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the nine months ended June 30, 2015.
(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, 2014	Gains/Losses Realized and	Gains/Losses Unrealized and	Transfer In/Out of Level 3	June 30, 2014

		Included in Earnings	Included in Other Comprehensive Income (Loss)		
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.

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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.

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, 2015		September 30, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$2,099,000	$2,162,821	$1,649,000	$1,775,715

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 $45.2 million at June 30, 2015 and $44.4 million at September 30, 2014. The fair value of the equity mutual fund was $36.9 million at June 30, 2015 and $35.3 million at September 30, 2014. The gross unrealized gain on this equity mutual fund was $8.5 million at June 30, 2015 and $8.4 million at September 30, 2014. The fair value of the stock of an insurance company was $6.4 million at June 30, 2015 and $6.6 million at September 30, 2014. The gross unrealized gain on this stock was $4.3 million at June 30, 2015 and $4.5 million at September 30, 2014. 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. In addition, the Company also enters into foreign exchange forward contracts to manage the risk of currency fluctuations associated with transportation costs denominated in Canadian currency in the Exploration and Production segment. 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

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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.

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, 2015 and September 30, 2014. Substantially all of the derivative financial instruments reported on those line items relate to commodity contracts and a small portion in the amount of $0.6 million represents a liability for foreign currency 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, 2015, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	168.2	Bcf (short positions)
Natural Gas	2.5	Bcf (long positions)
Crude Oil	2,178,000	Bbls (short positions)

As of June 30, 2015, the Company was hedging a total of $29.0 million of forecasted transportation costs denominated in Canadian dollars.

As of June 30, 2015, the Company had $242.4 million ($139.9 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $141.2 million ($81.5 million after tax) of such unrealized gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the underlying hedged transaction is recorded in earnings.

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, 2015 and 2014 (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 Three 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	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 Three Months	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 Three Months Ended June 30,

			Portion)	Ended June 30,				
	2015	2014		2015	2014		2015	2014
Commodity Contracts	$(8,845)	$(13,832)	Operating Revenue	$50,878	$(14,547)	Operating Revenue	$159	$(3,593)
Commodity Contracts	$(84)	$611	Purchased Gas	$(3)	$83	Not Applicable	$—	$—
Foreign Currency Contracts	$(554)	$—	Not Applicable	$—	$—	Not Applicable	$—	$—
Total	$(9,483)	$(13,221)		$50,875	$(14,464)		$159	$(3,593)

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The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Nine Months Ended June 30, 2015 and 2014 (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,	
	2015	2014		2015	2014		2015	2014
Commodity Contracts	$291,749	$(72,950)	Operating Revenue	$124,386	$(27,372)	Operating Revenue	$3,088	$(2,819)
Commodity Contracts	$4,316	$(4,953)	Purchased Gas	$4,884	$(3,549)	Not Applicable	$—	$—
Foreign Currency Contracts	$(554)	$—	Not Applicable	$—	$—	Not Applicable	$—	$—
Total	$295,511	$(77,903)		$129,270	$(30,921)		$3,088	$(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, 2015, the Company’s Energy Marketing segment had fair value hedges covering approximately 16.1 Bcf (16.0 Bcf of fixed price sales commitments and 0.1 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	Amount of Gain or (Loss) on the Hedged Item Recognized in the Consolidated Statement of Income for the

		Nine Months Ended June 30, 2015 (In Thousands)	Nine Months Ended June 30, 2015 (In Thousands)
Commodity Contracts	Operating Revenues	$(9,645)	$9,645
Commodity Contracts	Purchased Gas	$(1)	$1
		$(9,646)	$9,646

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 fourteen are in a net gain position. On average, the Company had $17.2 million of credit exposure per counterparty in a gain position at June 30, 2015. The maximum credit exposure per counterparty in a gain position at June 30, 2015 was $46.4 million. The Company's gain position on such derivative financial instruments for certain counterparties exceeded the established thresholds at which the counterparties would be required to post collateral. At June 30, 2015, collateral deposits of $32.4 million were posted. These collateral deposits are recorded as a component of Accounts Payable on the Consolidated Balance Sheet.

As of June 30, 2015, 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 liability were larger) and/or the Company's credit rating declined, then additional hedging collateral deposits may be required. At June 30, 2015, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $151.9 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, 2015.

For its exchange traded futures contracts, the Company was required to post $11.1 million in hedging collateral deposits as of June 30, 2015. 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 and the Company's right to receive 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,	
	2015	2014
Current Income Taxes		
Federal	$27,311	$31,496
State	14,195	11,736
Deferred Income Taxes		
Federal	(134,369)	90,693
State	(63,747)	28,702
	(156,610)	162,627

Deferred Investment Tax Credit	(311)	(326)
Total Income Taxes	$(156,921)	$162,301
Presented as Follows:		
Other Income	(311)	(326)
Income Tax Expense (Benefit)	(156,610)	162,627
Total Income Taxes	$(156,921)	$162,301

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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 (loss) before income taxes. The following is a reconciliation of this difference (in thousands):

	Nine Months Ended June 30,	
	2015	2014
U.S. Income (Loss) Before Income Taxes	$(348,645)	$404,284
Income Tax Expense (Benefit), Computed at U.S. Federal Statutory Rate of 35%	$(122,026)	$141,499
Increase (Reduction) in Taxes Resulting from:		
State Income Taxes	(32,209)	26,285
Miscellaneous	(2,686)	(5,483)
Total Income Taxes	$(156,921)	$162,301

During the quarter ended June 30, 2015, the balance of unrecognized tax benefits increased by $1.5 million as a result of a position taken on the recently filed federal tax return. Approximately $5.1 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 $5.1 million of the balance of uncertain tax positions may occur as a result of potential settlements with taxing authorities within the next twelve months.

Note 5 - Capitalization

Common Stock. During the nine months ended June 30, 2015, the Company issued 202,023 original issue shares of common stock as a result of stock option and SARs exercises and 47,490 original issue shares of common stock for restricted stock units that vested. In addition, the Company issued 94,675 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 66,406 original issue shares of common stock for the Company's 401(k) plans. The Company also issued 11,316 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, 2015. 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, 2015, 50,200 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

Current Portion of Long-Term Debt. None of the Company's long-term debt at June 30, 2015 will mature within the following twelve-month period.

Long-Term Debt. On June 25, 2015, the Company issued $450.0 million of 5.20% notes due July 15, 2025. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $445.7 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including the reduction of short-term debt.

Note 6 - Commitments and Contingencies

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory requirements. 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, 2015, 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 $13.7 million. The Company expects to recover such environmental clean-up costs through rate recovery over a period of approximately 12 years.

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The Company's estimated liability for clean-up costs discussed above includes a $12.2 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 been completed, and remedial work 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 2014 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 2014 Form 10-K. A listing of segment assets at June 30, 2015 and September 30, 2014 is shown in the tables below.

Quarter Ended June 30, 2015 (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	$159,404	$47,012	$126	$110,002	$22,420	$338,964	$634	$217	$339,815
Intersegment Revenues	$—	$21,833	$16,748	$2,614	$379	$41,574	$—	$(41,574)	$—
Segment Profit: Net Income (Loss)	$(323,113)	$17,714	$6,226	$5,727	$1,533	$(291,913)	$(28)	$(1,193)	$(293,134)

Nine Months Ended June 30, 2015 (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	$529,590	$154,515	$361	$630,049	$142,753	$1,457,268	$1,906	$677	$1,459,851
Intersegment Revenues	$—	$66,347	$58,541	$13,670	$796	$139,354	$—	$(139,354)	$—
Segment Profit: Net Income (Loss)	$(349,955)	$61,868	$24,254	$66,558	$7,732	$(189,543)	$66	$(2,247)	$(191,724)

(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, 2015	$2,718,451	$1,532,948	$491,020	$1,989,884	$89,197	$6,821,500	$76,650	$(8,482)	$6,889,668
At September 30, 2014	$3,100,514	$1,367,181	$326,662	$1,862,850	$76,238	$6,733,445	$86,460	$(80,308)	$6,739,597

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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)	$—
Segment Profit: Net Income (Loss)	$32,421	$17,934	$8,717	$4,826	$602	$64,500	$24	$(4)	$64,520

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

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,	2015	2014	2015	2014
Service Cost	$3,012	$2,997	$673	$735
Interest Cost	10,304	10,893	4,821	5,327
Expected Return on Plan Assets	(14,904)	(14,993)	(8,522)	(9,356)
Amortization of Prior Service Cost (Credit)	46	52	(478)	(534)
Amortization of Losses	9,032	9,002	1,037	661
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	88	456	4,739	5,325
Net Periodic Benefit Cost	$7,578	$8,407	$2,270	$2,158

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	Retirement Plan		Other Post-Retirement Benefits	
Nine Months Ended June 30,	2015	2014	2015	2014
Service Cost	$9,036	$8,990	$2,019	$2,204
Interest Cost	30,913	32,681	14,464	15,981
Expected Return on Plan Assets	(44,712)	(44,980)	(25,566)	(28,067)
Amortization of Prior Service Cost (Credit)	137	157	(1,435)	(1,604)
Amortization of Losses	27,097	27,005	3,111	1,984
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	8,434	10,591	17,055	19,314
Net Periodic Benefit Cost	$30,905	$34,444	$9,648	$9,812

(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, 2015, the Company contributed $18.0 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $1.9 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2015, the Company expects its contributions to the Retirement Plan to be in the range of zero to $2.0 million. In the remainder of 2015, the Company expects to contribute approximately $0.1 million to its VEBA trusts and 401(h) accounts.

Note 9 – Regulatory Matters

Following negotiations and other proceedings, on December 6, 2013, Distribution Corporation filed an agreement, also executed by the Department of Public Service and intervenors, extending existing rates through, at a minimum, September 30, 2015. 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 of the agreement. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. A $7.5 million refund provision was passed back to ratepayers during 2014 after the NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014. The agreement also states that nothing in the agreement precludes the parties from meeting to discuss extending the agreement on mutually acceptable terms, and presenting such extension to the NYPSC for approval. On May 22, 2015, Distribution Corporation filed with the NYPSC a Notice of Impending Settlement Discussions stating that settlement discussions would be scheduled in the near future, and that such discussions might include, among other things, the possible extension of the agreement on mutually acceptable terms. Settlement discussions, which under NYPSC regulations must remain confidential, have commenced.

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

OVERVIEW

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

The Company is a diversified energy company engaged principally in the production, gathering, transportation, distribution and marketing of natural gas. The Company operates an integrated business model centered in western New York and Pennsylvania, an area critical to the production and transportation of natural gas from the Marcellus Shale basin. The common geographic footprint of the Company's subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Marcellus Shale to markets in Canada and the eastern United States. The Company also develops and produces oil reserves, primarily in California. The Company reports financial results for five business segments.

For the quarter and nine months ended June 30, 2015, the Company experienced losses of $293.1 million and $191.7 million, respectively. The loss for both the quarter and nine months ended June 30, 2015 is driven largely by impairment charges of $588.7 million ($339.8 million after-tax) and $709.1 million ($409.3 million after-tax) recorded in the Exploration and Production segment during the quarter and nine months ended June 30, 2015, respectively. 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. Such costs are subject to a quarterly ceiling test prescribed by SEC Regulation S-X Rule 4-10 that determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. Due to significant declines in crude oil and natural gas commodity prices, the book value of the Company's oil and gas properties exceeded the ceiling at March 31, 2015 as well as June 30, 2015, resulting in the impairment charges mentioned above. The Company expects that the book value of its oil and gas properties will also exceed the ceiling at September 30, 2015 and December 31, 2015, resulting in additional impairment charges. For further discussion of the ceiling test and a sensitivity analysis concerning changes in crude oil and natural gas commodity prices and their impact on the ceiling test, refer to the Critical Accounting Estimates section below. For further discussion of the Company's earnings, refer to the Results of Operations section below.

The Company continues to develop its natural gas 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 790,000 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 1,239 Bcf at September 30, 2013 to 1,624 Bcf at September 30, 2014. 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, 2015, the Company's Exploration and Production segment had capital expenditures of $385.8 million in the Appalachian region, of which $344.9 million was spent towards the development of the Marcellus Shale. The amount spent towards the development of the Marcellus Shale represented approximately 49% of the Company's capital expenditures for the nine months ended June 30, 2015.

To facilitate the flow of natural gas from the Marcellus Shale, the Company continues to expand its gathering and pipeline infrastructure in the Gathering segment and the Pipeline and Storage segment. For the nine months ended June 30, 2015, the Gathering segment had capital expenditures of $87.2 million. The Pipeline and Storage segment's capital expenditures for the nine months ended June 30, 2015 were $114.7 million. The amount spent towards the development of gathering and pipeline infrastructure during the nine months ended June 30, 2015 represented approximately 29% of the Company's capital expenditures.

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. 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 2014 Form 10-K for further discussion.

From a capital resources perspective in June 2015, the Company issued $450.0 million of 5.20% notes due in July 2025. The notes were issued to enhance the Company's liquidity position and reduce short-term debt. Under the Company's existing indenture covenants, given the significant impairments recorded during the nine months ended June 30, 2015, the Company is precluded from issuing additional long-term unsecured indebtedness for a period of nine months beginning in October 2015. If the Company experiences additional impairments of its oil and gas properties in September 2015 and December 2015, the Company expects to be precluded from issuing incremental long-term debt beyond the nine month period beginning in October 2015. However, the Company expects that it could borrow under its credit facilities. In addition, the 1974 indenture would not preclude the Company from issuing new long-term debt to replace maturing long-term debt. On December 5, 2014, the Company entered into an Amended and Restated Credit Agreement that replaced the Company's existing $750.0 million committed credit facility with a substantially similar committed credit facility totaling $750.0 million that extends through December 5, 2019. The previous committed credit facility extended through January 6, 2017.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to "Critical Accounting Estimates" in Item 7 of the Company's 2014 Form 10-K. 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 that Form 10-K.

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. The book value of the oil and gas properties exceeded the ceiling at March 31, 2015 as well as June 30, 2015, resulting in cumulative impairment charges of $709.1 million ($409.3 million after-tax) for the nine months ended June 30, 2015. The impairment charge for the quarter ended June 30, 2015 was $588.7 million ($339.8 million after-tax). The 12-month average of the first day of the month price for crude oil for each month during the twelve months ended June 30, 2015, based on posted Midway Sunset prices, was $66.97 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, 2015, based on the quoted Henry Hub spot price for natural gas, was $3.39 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, 2015.) If natural gas average prices used in the ceiling test calculation at June 30, 2015 had been $1 per MMBtu lower, the book value of the Company's oil and gas properties would have exceeded the ceiling by approximately $837.6 million (after-tax), which would have resulted in an additional impairment charge of $497.8 million (after-tax) at June 30, 2015. If crude oil average prices used in the ceiling test calculation at June 30, 2015 had been $5 per Bbl lower, the book value of the Company's oil and gas properties would have exceeded the ceiling by approximately $381.3 million (after-tax), which would have resulted in an additional impairment charge of $41.5 million (after-tax) at June 30, 2015. If both natural gas and crude oil average prices used in the ceiling test calculation at June 30, 2015 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 $878.8 million (after-tax), which would have resulted in an additional impairment charge of $539.0 million (after-tax) at June 30, 2015. These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation, including, among others, changes in reserve quantities and future cost estimates. Looking ahead, the first day of the month Midway Sunset price for crude oil in July 2015 was $53.08 per Bbl. The first day of the month Henry Hub spot price for natural gas in July 2015 was $2.78 per MMBtu. Given these July prices, the potential that prices could stay at this level in future months, and the expected loss of significantly higher oil and gas prices from the 12-month average that will be used in the ceiling test at September 30, 2015 and December 31, 2015, the Company expects to experience significant ceiling test impairments in each of those quarters. 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 2014 Form 10-K.

RESULTS OF OPERATIONS

Earnings

The Company experienced a loss of $293.1 million for the quarter ended June 30, 2015 compared to earnings of $64.5 million for the quarter ended June 30, 2014. The decrease in earnings is primarily the result of a loss recognized in the Exploration and Production segment. Lower earnings in the Gathering segment and Pipeline and Storage segment, as well as a loss in the Corporate category, also contributed to the decrease. Higher earnings in the Energy Marketing segment and the Utility segment partially offset these decreases.

The Company experienced a loss of $191.7 million for the nine months ended June 30, 2015 compared to earnings of $242.0 million for the nine months ended June 30, 2014. The decrease in earnings is primarily the result of a loss recognized in

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the Exploration and Production segment. Lower earnings in the All Other category and a loss in the Corporate category also contributed to the decrease. Higher earnings in the Pipeline and Storage segment, Gathering segment, Utility segment and Energy Marketing segment partially offset these decreases.

The Company's earnings for the quarter and nine months ended June 30, 2015 include non-cash impairment charges of $588.7 million ($339.8 million after-tax) and $709.1 million ($409.3 million after-tax), respectively, recorded during the quarter and nine months ended June 30, 2015 for the Exploration and Production segment's oil and gas producing properties, as discussed above. 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

(Thousands)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Increase (Decrease)	Nine Months Ended June 30, 2015	Nine Months Ended June 30, 2014	Increase (Decrease)
Exploration and Production	$(323,113)	$32,421	$(355,534)	$(349,955)	$87,908	$(437,863)
Pipeline and Storage	17,714	17,934	(220)	61,868	58,444	3,424
Gathering	6,226	8,717	(2,491)	24,254	22,188	2,066
Utility	5,727	4,826	901	66,558	64,586	1,972
Energy Marketing	1,533	602	931	7,732	5,971	1,761
Total Reportable Segments	(291,913)	64,500	(356,413)	(189,543)	239,097	(428,640)
All Other	(28)	24	(52)	66	978	(912)
Corporate	(1,193)	(4)	(1,189)	(2,247)	1,908	(4,155)
Total Consolidated	$(293,134)	$64,520	$(357,654)	$(191,724)	$241,983	$(433,707)

Exploration and Production

Exploration and Production Operating Revenues

(Thousands)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Increase (Decrease)	Nine Months Ended June 30, 2015	Nine Months Ended June 30, 2014	Increase (Decrease)
Gas (after Hedging)	$105,108	$127,493	$(22,385)	$361,273	$374,738	$(13,465)
Oil (after Hedging)	52,887	76,415	(23,528)	161,804	216,750	(54,946)
Gas Processing Plant	621	1,100	(479)	2,394	3,827	(1,433)
Other	788	(3,486)	4,274	4,119	(1,186)	5,305
	$159,404	$201,522	$(42,118)	$529,590	$594,129	$(64,539)

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Production Volumes

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2015	2014	Increase (Decrease)	2015	2014	Increase (Decrease)
Gas Production (MMcf)						
Appalachia	30,830	35,098	(4,268)	104,221	98,640	5,581
West Coast	807	776	31	2,375	2,403	(28)
Total Production	31,637	35,874	(4,237)	106,596	101,043	5,553
Oil Production (Mbbl)						
Appalachia	7	6	1	22	23	(1)
West Coast	752	777	(25)	2,234	2,230	4
Total Production	759	783	(24)	2,256	2,253	3

Average Prices

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2015	2014	Increase (Decrease)	2015	2014	Increase (Decrease)
Average Gas Price/Mcf						
Appalachia	$2.11	$3.81	$(1.70)	$2.56	$3.84	$(1.28)
West Coast	$3.52	$7.02	$(3.50)	$4.30	$6.85	$(2.55)
Weighted Average	$2.15	$3.88	$(1.73)	$2.60	$3.91	$(1.31)
Weighted Average After Hedging	$3.32	$3.55	$(0.23)	$3.39	$3.71	$(0.32)
Average Oil Price/Bbl						
Appalachia	$56.54	$100.91	$(44.37)	$62.29	$96.76	$(34.47)
West Coast	$52.07	$101.83	$(49.76)	$54.48	$99.82	$(45.34)
Weighted Average	$52.12	$101.82	$(49.70)	$54.56	$99.79	$(45.23)
Weighted Average After Hedging	$69.65	$97.54	$(27.89)	$71.72	$96.19	$(24.47)

2015 Compared with 2014

Operating revenues for the Exploration and Production segment decreased $42.1 million for the quarter ended June 30, 2015 as compared with the quarter ended June 30, 2014. Gas production revenue after hedging decreased $22.4 million due to a $0.23 per Mcf decrease in the weighted average price of gas after hedging and a decrease in production due to temporary pricing related curtailments. Oil production revenue after hedging decreased $23.5 million due to a $27.89 per Bbl decrease in the weighted average price of oil after hedging coupled with a slight decrease in production. The decrease in operating revenues was partially offset by a $4.3 million increase in other revenue. This was largely due to the impact of mark-to-market adjustments related to hedging ineffectiveness (mostly associated with certain crude oil hedges).

Operating revenues for the Exploration and Production segment decreased $64.5 million for the nine months ended June 30, 2015 as compared with the nine months ended June 30, 2014. Crude oil production revenue after hedging decreased $54.9 million due to a $24.47 per Bbl decrease in the weighted average price of oil after hedging. Gas production revenue after hedging decreased $13.5 million as a $0.32 per Mcf decrease in the weighted average price of natural gas after hedging more than offset the impact of an increase in gas production volume. The increase in gas production volume was largely due to increased development within the Marcellus Shale formation, mainly in Lycoming, Elk, Cameron and McKean counties in Pennsylvania, which more than offset the impact of the temporary pricing related curtailments experienced during the quarters ended March 31, 2015 and June 30, 2015. Partially offsetting these decreases was a $5.3 million increase in other revenue. This was largely due to the impact of mark-to-market adjustments related to hedging ineffectiveness (mostly associated with certain crude oil hedges), partially offset by the impact from the receipt of settlement proceeds in fiscal 2014 related to former insurance policies that did not recur in the current year.

The Exploration and Production segment's loss for the quarter ended June 30, 2015 was $323.1 million, a decrease of $355.5 million when compared with earnings of $32.4 million for the quarter ended June 30, 2014. The decrease in earnings is primarily the result of an impairment charge of $339.8 million, as discussed above. The decrease was also attributable to lower crude oil prices after hedging ($13.8 million), lower natural gas prices after hedging ($4.8 million), lower natural gas production ($9.8 million), lower crude oil production ($1.5 million), higher operating expenses ($0.8 million) and higher interest expense ($0.7 million). The increase in operating expenses was largely due to an accrual for the estimated purchase of emission allowances recorded in fiscal 2015 and higher personnel costs. The increase in interest expense was largely due to increased borrowing from affiliates and a reduction in capitalized interest. In addition, the non-recurrence of the reversal of a plugging and abandonment accrual recorded in fiscal 2014 decreased earnings by $2.7 million. The plugging and abandonment accrual recorded in fiscal 2014 related to offshore properties that were no longer owned by the Exploration and Production segment in fiscal 2014. These decreases in earnings were partially offset by the impact of lower depletion expenses ($12.2 million) due to the impact of increased reserves achieved with lower finding and development costs per Mcfe (due to increased operating efficiencies), the impact of an impairment charge recorded in the previous quarter, and lower production. In addition, the impact of mark-to-market adjustments ($2.4 million), lower production costs ($2.8 million) and lower income taxes ($0.9 million) helped to further offset the earnings reduction. The decrease in production costs was largely due to decreased steam costs (due to lower fuel prices) and well repair costs in California. In addition, there was a decrease in transportation costs due to the impact of production curtailments in the Appalachian region. The decrease in income taxes is largely due to a reduction in state income taxes partially offset by the non-recurrence of a favorable settlement with a taxing authority that occurred in fiscal 2014.

The Exploration and Production segment's loss for the nine months ended June 30, 2015 was $350.0 million, a decrease of $437.9 million when compared with earnings of $87.9 million for the nine months ended June 30, 2014. The decrease in earnings is primarily the result of the cumulative impairment charge of $409.3 million. The decrease was also attributable to lower crude oil prices after hedging ($35.9 million), lower natural gas prices after hedging ($22.1 million), higher production costs ($5.7 million), higher operating expenses ($2.4 million), the non-recurrence of insurance settlement proceeds received in 2014 ($1.3 million) and higher interest expense ($0.6 million). The increase in production costs was largely attributable to higher transportation costs associated with increased production volumes transported by Midstream Corporation. These decreases in earnings were partially offset by the impact of higher natural gas production ($13.4 million), lower income taxes ($4.0 million), the impact of mark-to-market adjustments ($4.3 million), higher crude oil production ($0.2 million) and lower depletion expenses ($14.1 million) due to the impact of increased reserves achieved with lower finding and development costs per Mcfe (due to increased operating efficiencies) and the impact of an impairment charge recorded in the previous quarter. The decrease in income tax expense was largely due to a reduction in state income taxes partially offset by the impact of a favorable settlement with a taxing authority that occurred in fiscal 2014. In addition, the non-recurrence of the plugging and abandonment accrual and the deferred state income tax adjustment recorded in fiscal 2014 increased fiscal 2015 earnings by $0.6 million and $3.0 million, respectively. During the quarter ended March 31, 2014, the New York fiscal year 2014-2015 Executive Budget legislation was signed into law, which included a reduction of the corporate tax rate. However, as a result of increasing Appalachian production in Pennsylvania, the Company also remeasured its accumulated deferred state income taxes, which led to an overall increase in tax expense in fiscal 2014.

Pipeline and Storage

Pipeline and Storage Operating Revenues

(Thousands)	Three Months Ended June 30, 2015	2014	Increase (Decrease)	Nine Months Ended June 30, 2015	2014	Increase (Decrease)
Firm Transportation	$50,553	$50,142	$411	$163,770	$158,580	$5,190
Interruptible Transportation	656	709	(53)	2,187	2,053	134
	51,209	50,851	358	165,957	160,633	5,324
Firm Storage Service	17,514	17,131	383	53,153	52,787	366
Interruptible Storage Service	—	7	(7)	3	10	(7)
Other	122	546	(424)	1,749	2,862	(1,113)
	$68,845	$68,535	$310	$220,862	$216,292	$4,570

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Pipeline and Storage Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2015	2014	Increase (Decrease)	2015	2014	Increase (Decrease)
Firm Transportation	155,819	158,619	(2,800)	572,453	575,253	(2,800)
Interruptible Transportation	3,105	998	2,107	8,833	3,778	5,055
	158,924	159,617	(693)	581,286	579,031	2,255

2015 Compared with 2014

Operating revenues for the Pipeline and Storage segment increased $0.3 million for the quarter ended June 30, 2015 as compared with the quarter ended June 30, 2014. The increase was primarily due to an increase in both transportation ($0.4 million) and storage service revenues ($0.4 million), partially offset by a decrease in other revenues of $0.4 million. The increase in transportation revenues was largely due to demand charges for transportation service from Supply Corporation’s Mercer Expansion Project, which was placed in service in the current year's first quarter. This increase to transportation revenues was partially offset by a decrease in revenue as a result of Empire renegotiating certain long-term contracts for transportation service from the East Canadian border, on the original Empire line. The increase in storage service revenues was primarily due to an Open Season Supply Corporation held for additional capacity. Partially offsetting these increases was a decrease in other revenues of $0.4 million due to a decrease in gas processed for others.

Operating revenues for the Pipeline and Storage segment increased $4.6 million for the nine months ended June 30, 2015 as compared with the nine months ended June 30, 2014. The increase was primarily due to an increase in transportation revenues of $5.3 million, partially offset by a decrease in other revenues of $1.1 million. The increase in transportation revenues was largely due to demand charges for transportation service from Supply Corporation’s Mercer Expansion Project, which was placed in service in November 2014. Also contributing to the increase in transportation revenues was additional non-expansion revenue as a result of both new short-term and long-term contracts for transportation service from various Open Seasons Supply Corporation has held. Partially offsetting these increases was a decrease in cashout revenues of $0.8 million (reported as a part of other revenue in the table above). Cashout revenues are completely offset by purchased gas expense and as a result have no impact on earnings.

Transportation volume for the quarter ended June 30, 2015 decreased by 0.7 Bcf from the prior year’s quarter. For the nine months ended June 30, 2015, transportation volume increased by 2.3 Bcf from the prior year's nine-month period. The increase in transportation volume for the nine-month period primarily reflects the impact of the Mercer Expansion Project being placed in service and new contracts for transportation service. Volume fluctuations generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

The Pipeline and Storage segment’s earnings for the quarter ended June 30, 2015 were $17.7 million, a decrease of $0.2 million when compared with earnings of $17.9 million for the quarter ended June 30, 2014. The decrease in earnings is primarily due to an increase in depreciation expense ($0.4 million) attributable to incremental depreciation expense related to projects that were placed in service within the last year. An increase in property taxes of $0.2 million, primarily attributable to increased assessments, also contributed to the decrease in earnings. These earnings decreases were largely offset by the earnings impact of higher transportation and storage revenues of $0.5 million, as discussed above.

The Pipeline and Storage segment's earnings for the nine months ended June 30, 2015 were $61.9 million, an increase of $3.5 million when compared with earnings of $58.4 million for the nine months ended June 30, 2014. The increase in earnings is primarily due to the earnings impact of higher transportation and storage revenues of $3.7 million, as discussed above, combined with an increase in the allowance for funds used during construction (equity component) of $1.5 million. The increase in the allowance for funds used during construction is mainly due to capital costs incurred during the nine months ended June 30, 2015 related to various expansion projects currently under construction, in addition to the Mercer Expansion Project, which was under construction and placed in service during the first quarter of fiscal 2015. These earnings increases were partially offset by an increase in depreciation expense ($0.8 million) and an increase in property taxes ($0.8 million). The increase in depreciation expense was attributable to incremental depreciation expense related to projects that were placed in service within the last year. The increase in property taxes was attributable to increased assessments.

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Gathering

Gathering Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2015	2014	Increase (Decrease)	2015	2014	Increase (Decrease)
Gathering	$16,748	$18,740	$(1,992)	$58,541	$48,541	$10,000
Processing and Other Revenues	126	343	(217)	361	772	(411)
	$16,874	$19,083	$(2,209)	$58,902	$49,313	$9,589

Gathering Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2015	2014	Increase (Decrease)	2015	2014	Increase (Decrease)
Gathered Volume - (MMcf)	30,648	35,272	(4,624)	106,695	97,240	9,455

2015 Compared with 2014

Operating revenues for the Gathering segment decreased $2.2 million for the quarter ended June 30, 2015 as compared with the quarter ended June 30, 2014. This decrease was largely due to a decrease in gathering revenues driven by a 4.6 Bcf decrease in gathered volume (due to a decrease in Seneca production). The overall decrease in gathered volume was largely due to a 5.2 Bcf decrease in gathered volume on Midstream Corporation's Trout Run Gathering System (Trout Run) and a 4.0 Bcf decrease in gathered volume on Midstream Corporation's Covington Gathering System (Covington) partially offset by a 4.9 Bcf increase in gathered volume on Midstream Corporation's Clermont Gathering System (Clermont), which was placed in service in July 2014. Most of the decrease in gathered volume is attributable to a decrease in Seneca's Marcellus Shale production, primarily in Tioga and Lycoming counties in Pennsylvania, largely due to the impact of pricing related curtailments during the quarter ended June 30, 2015.

Operating revenues for the Gathering segment increased $9.6 million for the nine months ended June 30, 2015 as compared with the nine months ended June 30, 2014. This increase was largely due to an increase in gathering revenues driven by a 9.5 Bcf increase in gathered volume combined with higher gathering rates. The overall increase in gathered volume was largely due to a 12.4 Bcf increase in gathered volume on Clermont, which was placed in service in July 2014, and an 8.8 Bcf increase in gathered volume on Trout Run. The increase in gathered volume is attributable to an increase in Seneca's Marcellus Shale production, primarily in Lycoming, Elk, Cameron and McKean counties in Pennsylvania. These increases in gathered volume were partially offset by a 10.8 Bcf decrease in gathered volume on Covington due to a decline in Seneca's Marcellus Shale production in the Covington area of Tioga County, Pennsylvania.

The Gathering segment's earnings for the quarter ended June 30, 2015 were $6.2 million, a decrease of $2.5 million when compared with earnings of $8.7 million for the quarter ended June 30, 2014. The decrease in earnings is mainly due to the earnings impact of lower gathering revenues ($1.4 million), due to lower gathered volumes (as discussed above), and higher income tax expense ($0.7 million). The increase in income tax expense was largely due to the impact of the provision-to-return adjustments.

The Gathering segment's earnings for the nine months ended June 30, 2015 were $24.3 million, an increase of $2.1 million when compared with earnings of $22.2 million for the nine months ended June 30, 2014. The increase in earnings is mainly due to the earnings impact of higher gathering revenues ($6.2 million) and lower interest expense ($0.7 million). These were partially offset by higher depreciation expense ($2.5 million), higher income tax expense ($1.2 million) and higher operating expenses ($1.1 million). The significant growth of Trout Run and Clermont is primarily responsible for the revenue and operating expense variations. During the quarter ended March 31, 2015, the Company recorded long-lived asset impairment charges related to its gathering facilities at Midstream Corporation's Tionesta Gathering System, which, combined with greater plant balances, lead to an increase in depreciation expense. The increase in income tax expense was due to the aforementioned provision-to-return adjustments and higher state income taxes.

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Utility

Utility Operating Revenues

(Thousands)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Increase (Decrease)	Nine Months Ended June 30, 2015	Nine Months Ended June 30, 2014	Increase (Decrease)
Retail Sales Revenues:						
Residential	$74,872	$101,136	$(26,264)	$436,006	$536,527	$(100,521)
Commercial	8,644	13,204	(4,560)	56,707	72,535	(15,828)
Industrial	337	510	(173)	2,388	3,390	(1,002)
	83,853	114,850	(30,997)	495,101	612,452	(117,351)
Transportation	26,543	28,109	(1,566)	122,653	129,718	(7,065)
Off-System Sales	—	1,938	(1,938)	11,773	19,049	(7,276)
Other	2,220	2,517	(297)	14,192	7,207	6,985
	$112,616	$147,414	$(34,798)	$643,719	$768,426	$(124,707)

Utility Throughput

(MMcf)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Increase (Decrease)	Nine Months Ended June 30, 2015	Nine Months Ended June 30, 2014	Increase (Decrease)
Retail Sales:						
Residential	8,287	8,826	(539)	56,315	56,473	(158)
Commercial	1,142	1,238	(96)	8,239	8,357	(118)
Industrial	34	(12)	46	316	377	(61)
	9,463	10,052	(589)	64,870	65,207	(337)
Transportation	13,993	14,841	(848)	68,509	70,188	(1,679)
Off-System Sales	—	525	(525)	3,787	4,335	(548)
	23,456	25,418	(1,962)	137,166	139,730	(2,564)

Degree Days

Three Months Ended June 30,	Normal	2015	2014	Percent Colder (Warmer) Than Normal[1]	Percent Colder (Warmer) Than Prior Year[1]
Buffalo	912	778	841	(14.7)%	(7.5)%
Erie	871	729	797	(16.3)%	(8.5)%
Nine Months Ended June 30,					
Buffalo	6,455	6,898	6,957	6.9%	(0.8)%
Erie	6,023	6,535	6,625	8.5%	(1.4)%

(1) Percents compare actual 2015 degree days to normal degree days and actual 2015 degree days to actual 2014 degree days.

2015 Compared with 2014

Operating revenues for the Utility segment decreased $34.8 million for the quarter ended June 30, 2015 as compared with the quarter ended June 30, 2014. This decrease largely resulted from a $31.0 million decrease in retail gas sales revenues, a $1.9 million decrease in off-system sales revenue and a $1.6 million decrease in transportation revenues. The decrease in retail gas revenues is mostly due to a decrease in the cost of gas sold (per Mcf) coupled with lower volumes due to warmer weather. During the quarter ended June 30, 2015, the Company did not engage in off-system sales as it took advantage of lower priced gas

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in the Appalachian basin relative to the price of gas originating from the Gulf of Mexico area, which reduced the opportunity for off-system sales. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal. The decrease in transportation revenues was due to a 0.8 Bcf decrease in throughput due to warmer weather.

Operating revenues for the Utility segment decreased $124.7 million for the nine months ended June 30, 2015 as compared with the nine months ended June 30, 2014. This decrease largely resulted from a $117.4 million decrease in retail gas sales revenues, a $7.3 million decrease in off-system sales, and a $7.1 million decrease in transportation revenues. These were partially offset by a $7.0 million increase in other revenues. The decrease in retail gas revenues is mostly due to a decrease in the cost of gas sold (per Mcf) coupled with lower volumes due to warmer weather. The decrease in off-system sales is due to market conditions that have continued to reduce the price at which off-system gas could be sold and the opportunity for off-system gas sales. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal. The decrease in transportation revenues was due to a 1.7 Bcf decrease in throughput due to slightly warmer weather. The increase in other revenues was largely due to a regulatory adjustment recorded during fiscal 2015 to recognize an under-collection from customers of a New York State regulatory assessment, a decrease in an accrual for an estimated earnings sharing refund provision (pursuant to the terms of the most recent settlement with the NYPSC), and an increase in capacity release revenues. As a result of a colder than normal winter during fiscal 2014, the demand for capacity releases increased as contracts for Distribution Corporation’s fiscal 2015 capacity were being executed. Subsequently, the rates paid and resulting revenues for capacity releases increased in fiscal 2015 compared to fiscal 2014.

The Utility segment’s earnings for the quarter ended June 30, 2015 were $5.7 million, an increase of $0.9 million when compared with earnings of $4.8 million for the quarter ended June 30, 2014. This increase was largely due to a $0.7 decrease in income tax expense largely attributable to provision-to-return adjustments.

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, 2015, the WNC increased earnings by approximately $0.1 million, as the weather was warmer than normal. 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.

The Utility segment’s earnings for the nine months ended June 30, 2015 were $66.6 million, an increase of $2.0 million when compared with earnings of $64.6 million for the nine months ended June 30, 2014. This increase was largely due to $3.7 million of regulatory adjustments (discussed above) and a $1.0 million increase from the earnings impact of higher capacity release revenues (discussed above). These increases were partially offset by the earnings impact of a $2.3 million increase in operating expenses (largely due to operating costs associated with the planned replacement of the Utility segment’s legacy mainframe systems).

For the nine months ended June 30, 2015, the WNC reduced earnings by approximately $2.5 million, as the weather was colder than normal. For the nine months ended June 30, 2014, the WNC reduced earnings by approximately $3.0 million, as the weather was colder than normal.

Energy Marketing

Energy Marketing Operating Revenues

(Thousands)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Increase (Decrease)	Nine Months Ended June 30, 2015	Nine Months Ended June 30, 2014	Increase (Decrease)
Natural Gas (after Hedging)	$22,799	$46,415	$(23,616)	$143,495	$244,230	$(100,735)
Other	—	—	—	54	43	11
	$22,799	$46,415	$(23,616)	$143,549	$244,273	$(100,724)

Energy Marketing Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2015	2014	Increase (Decrease)	2015	2014	Increase (Decrease)
Natural Gas – (MMcf)	8,289	8,930	(641)	40,215	45,848	(5,633)

2015 Compared with 2014

Operating revenues for the Energy Marketing segment decreased $23.6 million for the quarter ended June 30, 2015 as compared with the quarter ended June 30, 2014. Operating revenues for the Energy Marketing segment decreased $100.7 million for the nine months ended June 30, 2015 as compared with the nine months ended June 30, 2014. The decrease for the quarter and nine-month period is primarily due to a decline in gas sales revenue due to a lower average price of natural gas period over period and a decrease in volume sold to retail customers.

The Energy Marketing segment's earnings for the quarter ended June 30, 2015 were $1.5 million, an increase of $0.9 million when compared with earnings of $0.6 million for the quarter ended June 30, 2014. This increase in earnings was largely attributable to higher margin of $1.0 million. The increase in margin largely reflects higher average margins per Mcf, a reduction in pipeline capacity reservation charges due to the turn back of certain storage and transportation capacity, and an increase in the benefit the Energy Marketing segment realized from its contracts for storage capacity.

The Energy Marketing segment's earnings for the nine months ended June 30, 2015 were $7.7 million, an increase of $1.7 million when compared with earnings of $6.0 million for the nine months ended June 30, 2014. This increase in earnings was largely attributable to higher margin of $1.9 million. The increase in margin largely reflects a reduction in pipeline capacity reservation charges due to the turn back of certain storage and transportation capacity, higher average margins per Mcf, and an increase in the benefit the Energy Marketing segment realized from its contracts for storage capacity. These increases were partially offset by slightly lower margin associated with unbilled revenue. The Energy Marketing segment began recording unbilled revenue and related gas costs during the quarter ended December 31, 2013. Prior to that quarter, Energy Marketing segment revenues and related purchased gas costs had been recorded when billed, resulting in a one-month lag. As a result of eliminating the one-month lag, revenues and related gas costs for the nine months ended June 30, 2014 reflected ten months of activity whereas the revenue and related gas costs for the nine months ended June 30, 2015 reflect nine months of activity.

Corporate and All Other

2015 Compared with 2014

Corporate and All Other operations recorded a loss of $1.2 million for the quarter ended June 30, 2015, compared to earnings of less than $0.1 million for the quarter ended June 30, 2014. Earnings primarily decreased as the result of higher income tax expense for the quarter ended June 30, 2015 compared with the quarter ended June 30, 2014.

For the nine months ended June 30, 2015, Corporate and All Other operations had a loss of $2.2 million, a decrease of $5.1 million when compared with earnings of $2.9 million for the nine months ended June 30, 2014. Earnings decreased primarily due to the non-recurrence of a $3.6 million death benefit gain on life insurance proceeds recognized during the quarter ended March 31, 2014, which was recorded in Other Income. A $0.6 million decrease in margin from the sale of standing timber (including certain timber stumpage tracts by Seneca's land and timber division) further decreased earnings. In addition, earnings were decreased by the impact of higher income tax expense of $1.0 million for the nine months ended June 30, 2015 compared to the nine months ended June 30, 2014.

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

Interest on long-term debt increased $0.1 million for the quarter ended June 30, 2015 as compared with the quarter ended June 30, 2014. This increase was due to additional long-term debt being issued during the quarter. The Company issued $450 million of 5.20% notes in June 2015. This increase was largely offset by the impact of higher capitalized interest (mostly Midstream Corporation) during the quarter ended June 30, 2015 compared to the quarter ended June 30, 2014. For the nine months ended June 30, 2015, interest on long-term debt decreased $0.9 million as compared with the nine months ended June 30, 2014. This decrease was due to an increase in capitalized interest (mostly in Midstream Corporation) for the nine months ended June 30, 2015 compared to the nine months ended June 30, 2014. This decrease was partially offset by an increase to interest due to additional long-term debt being issued in June 2015 (discussed above).

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CAPITAL RESOURCES AND LIQUIDITY

The Company's primary sources of cash during the nine-month period ended June 30, 2015 consisted of cash provided by operating activities and proceeds from the issuance of long-term debt. The Company's primary source of cash during the nine-month period ended June 30, 2014 consisted of cash provided by operating activities. These sources of cash were supplemented by net proceeds from the issuance of common stock for both the nine months ended June 30, 2015 and June 30, 2014, including the issuance of original issue shares for the Direct Stock Purchase and Dividend Reinvestment Plan.

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, impairment of oil and gas producing properties, deferred income taxes and stock-based compensation.

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 $712.6 million for the nine months ended June 30, 2015, a decrease of $13.0 million compared with $725.6 million provided by operating activities for the nine months ended June 30, 2014. The decrease in cash provided by operating activities reflects lower cash provided by operating activities in the Exploration and Production segment and the Corporate category. The decrease is partially offset by an increase in cash provided by operating activities in the Utility segment and Gathering segment. The decrease in the Exploration and Production segment is primarily due to lower cash receipts from crude oil and natural gas production as a result of lower crude oil and natural gas prices. The decrease in the Corporate category is primarily due to the receipt of life insurance proceeds during the quarter ended March 31, 2014. The increase in the Utility segment is primarily due to the timing of gas cost recovery and the timing of receivable collections. Lastly, the increase in the Gathering segment is primarily a result of an increase in Seneca's Marcellus Shale production, which has resulted in higher gathering revenues at the Trout Run and Clermont gathering systems.

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Investing Cash Flow

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets totaled $704.9 million during the nine months ended June 30, 2015 and $664.0 million for the nine months ended June 30, 2014. 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)	2015		2014		Increase(Decrease)	
Exploration and Production:						
Capital Expenditures	$437.4	(1)	$444.4	(2)	$ (7.0	)
Pipeline and Storage:						
Capital Expenditures	114.7	(1)	64.9	(2)	49.8	
Gathering:						
Capital Expenditures	87.2	(1)	93.2	(2)	(6.0	)
Utility:						
Capital Expenditures	65.3	(1)	60.9	(2)	4.4	
All Other:						
Capital Expenditures	0.3	(1)	0.6	(2)	(0.3	)
	$704.9		$664.0		$ 40.9	

(1) At June 30, 2015, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $64.3 million, $28.0 million, $21.4 million and $8.9 million, respectively, of accounts payable and accrued liabilities related to capital expenditures. At September 30, 2014, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $80.1 million, $28.1 million, $20.1 million and $8.3 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

(2) At June 30, 2014, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $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.

Exploration and Production

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2015 were primarily well drilling and completion expenditures and included approximately $385.8 million for the Appalachian region (including $344.9 million in the Marcellus Shale area) and $51.6 million for the West Coast region. These amounts included approximately $155.4 million spent to develop proved undeveloped reserves.

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.

Pipeline and Storage

The Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2015 were mainly for expenditures related to Supply Corporation's Northern Access 2015 Project ($26.3 million), Supply Corporation's Westside Expansion and Modernization Project ($26.3 million), Empire and Supply Corporation's Tuscarora Lateral Project ($24.3 million) and Supply Corporation's Mercer Expansion Project ($5.1 million). In addition, the Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2015 also include additions, improvements and replacements to this segment’s transmission and gas storage systems.   The majority of the Pipeline and Storage capital expenditures for the nine months ended June 30, 2014 were mainly related to additions, improvements, and replacements to this segment’s transmission and gas storage systems and also included $17.3 million spent on the Mercer Expansion Project.

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, 2015, the total amount reserved for the Pipeline and Storage segment's preliminary survey and investigation costs was $7.4 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 executed a service agreement with Range Resources for 105,000 Dth per day, all of the project capacity, for service which began November 1, 2014. The cost estimate is $34.2 million, of which $30.1 million is for expansion and $4.1 million is for replacement. Supply Corporation constructed the required 3,550 horsepower of compression at Mercer, and replaced 2.08 miles of 24" pipeline, both under its FERC blanket certificate authorization. As of June 30, 2015, approximately $32.8 million has been spent on the Mercer Expansion Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2015.

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 received its FERC 7(c) certificate on March 2, 2015 and executed two service agreements for all 175,000 Dth per day of project capacity, for service expected to begin by November 2015. The Westside Expansion and Modernization Project facilities include the replacement of approximately 23.3 miles of 20" pipe with 24" pipe and the addition of 3,550 horsepower of compression at Mercer. The cost estimate is $86.0 million, of which $44.9 million is related to expansion and the remainder is for replacement. As of June 30, 2015, approximately $31.1 million has been capitalized as Construction Work in Progress for the Westside Expansion and Modernization Project.

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 Seneca Resources' 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 November 2015. Supply

Corporation and TGP received their FERC 7(c) certificates on February 27, 2015 and have executed the Capacity Lease agreement. The cost estimate for the Northern Access 2015 project is $66 million. As of June 30, 2015, approximately $37.4 million has been capitalized as Construction Work in Progress for the Northern Access 2015 project.

Supply Corporation and Empire have been working with Seneca Resources to develop a project which would move significant prospective Marcellus production from Seneca Resources' Western Development Area at Clermont to an Empire interconnection 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 and to the TGP line serving the U.S. Northeast, all in late calendar year 2016. The Northern Access 2016 project involves the construction of approximately 99.7 miles of 24" pipeline and approximately 27,500 horsepower of compression on the two systems. The preliminary cost estimate for the Northern Access 2016 project is $453 million. Supply Corporation, Empire and Seneca Resources executed anchor shipper agreements for 350,000 Dth per day of firm transportation delivery capacity to Chippawa and 140,000 Dth per day of firm transportation capacity to a new interconnection with TGP's 200 Line on this project. On July 24, 2014, Supply Corporation and Empire initiated the FERC NEPA Pre-filing process on this project and both parties filed a joint FERC 7(b) and 7(c) application in early March 2015. As of June 30, 2015, approximately $7.4 million has been spent to study the Northern Access 2016 project. 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.

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. Empire and Rochester Gas & Electric ("RG&E"), Empire's largest LDC connected market, 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 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" and 16" pipeline and an 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. Empire and Supply Corporation received a FERC certificate on March 10, 2015. Both parties have executed the Capacity Lease and Empire has executed service agreements with all three of its project shippers. The cost estimate for the Tuscarora Lateral Project is $60.0 million. As of June 30, 2015, approximately $26.0 million has been capitalized as Construction Work in Progress for the Tuscarora Lateral Project.

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 Millennium Pipeline at Corning or from new interconnections in Tioga County, Pennsylvania, to TransCanada Pipeline and the TGP 200 Line ("Central Tioga County Extension"). In addition, the connection to Supply Corporation afforded by the Tuscarora Lateral Project could allow those Marcellus supplies to be sourced from other parts of Supply Corporation. 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 $114 million to $150 million depending on requested receipt points. As of June 30, 2015, approximately $0.3 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, 2015.

Gathering

The majority of the Gathering segment capital expenditures for the nine months ended June 30, 2015 were for the construction of Midstream Corporation's Clermont Gathering System, as discussed below. 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.

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 continued buildout is anticipated to be in the range of $250 million to $500 million. As of June 30, 2015, approximately $185.2 million has been spent on the Clermont Gathering System, including approximately $86.1 million spent during the nine months ended June 30, 2015, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2015.

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, 2015, the Company has spent approximately $163.0 million in costs related to this project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2015.

Utility

The majority of the Utility segment capital expenditures for the nine months ended June 30, 2015 and June 30, 2014 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, 2015 and June 30, 2014 also include $12.9 million and $13.0 million, respectively, related to the replacement of the Utility segment's customer information system, which is scheduled to be placed in service in the fall of 2015.

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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. In addition, the Company issued additional long-term debt in June 2015 to enhance its liquidity position, including the reduction of short-term debt. Going forward, while the Company expects to use cash on hand and cash from operations as the first means of financing these projects, the Company may issue short-term debt as necessary during fiscal 2015 to help meet its capital expenditures needs. The level of short-term borrowings will depend upon the amounts of cash provided by operations, which, in turn, will likely be impacted by natural gas and crude oil prices combined with production from existing wells.

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

Financing Cash Flow

Consolidated short-term debt decreased $85.6 million when comparing the balance sheet at June 30, 2015 to the balance sheet at September 30, 2014. The maximum amount of short-term debt outstanding during the nine months ended June 30, 2015 was $260.8 million. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures, 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. At June 30, 2015, the Company did not have any outstanding commercial paper or short-term notes payable to banks.

On December 5, 2014, the Company entered into an Amended and Restated Credit Agreement with a syndicate of 14 banks. The agreement replaced the Company's previous $750.0 million committed credit facility with a substantially similar facility totaling $750.0 million. The new facility extends through December 5, 2019. 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 $500.0 million. At June 30, 2015, the commercial paper program was backed by the Amended and Restated $750.0 million syndicated committed credit facility. Under the new 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 December 5, 2019. At June 30, 2015, the Company's debt to capitalization ratio (as calculated under the facility) was .48. The constraints specified in the committed credit facility would have permitted an additional $2.07 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 credit facilities or rely upon other liquidity sources, including cash provided by operations.

The Company's Amended and Restated $750.0 million committed credit facility, like the one it replaced, also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of June 30, 2015, the Company did not have any debt outstanding under the committed credit facility.

On June 25, 2015, the Company issued $450.0 million of 5.20% notes due July 15, 2025. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $445.7 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including the reduction of short-term debt.

None of the Company's long-term debt at June 30, 2015 and 2014 had a maturity date within the following twelve-month period.

The Company's embedded cost of long-term debt was 5.49% and 5.58% at June 30, 2015 and June 30, 2014, respectively.

Under the Company's existing indenture covenants, at June 30, 2015, the Company is precluded from issuing additional long-term unsecured indebtedness for a period of nine months beginning in October 2015 as a result of impairments of its oil and gas properties recognized during the nine months ended June 30, 2015, as discussed above. The 1974 indenture would not preclude the Company from issuing new indebtedness to replace maturing debt. If the Company experiences additional impairments of its oil and gas properties in September 2015 and December 2015, the Company, under its 1974 indenture, expects to be precluded from issuing incremental long-term debt beyond the nine month period beginning in October 2015. However, the Company expects that it could borrow under its credit facilities. The Company's present liquidity position is believed to be adequate to satisfy known demands. Please refer to the Critical Accounting Estimates section above for a sensitivity analysis concerning commodity price changes and their impact on the ceiling test.

The Company's 1974 indenture pursuant to which $99.0 million (or 4.7%) of the Company's long-term debt (as of June 30, 2015) 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.

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 $51.5 million. These leases have been entered into for the use of compressors, drilling rigs, buildings, meters and other items and are accounted for as operating leases.

OTHER MATTERS

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

During the nine months ended June 30, 2015, the Company contributed $18.0 million to its Retirement Plan and $1.9 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2015, the

Company expects its contributions to the Retirement Plan to be in the range of zero to $2.0 million. In the remainder of 2015, the Company expects to contribute $0.1 million to its VEBA trusts and 401(h) accounts.

Market Risk Sensitive Instruments

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives have or will become effective as federal agencies (including the CFTC, various banking regulators and the SEC) adopt rules to implement the law. 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, the CFTC has imposed numerous registration, swaps documentation, business conduct, reporting, and recordkeeping requirements on swap dealers and major swap participants, which frequently are counterparties to the Company's derivative hedging transactions. Similarly, the CFTC and various banking regulators have proposed rules that would require swap dealers and major swap participants subject to their jurisdiction to comply with certain obligations relating to capitalization and the collection of initial and variation margin from certain counterparties, although the recent proposals do not mandate the collection of margin from counterparties that qualify as non-financial end users, such as the Company. Regardless of the final capital and margin rules, concern remains that swap dealers and major swap participants will pass along their increased costs stemming from the final and proposed rules through higher transaction costs and prices or other direct or indirect costs. 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 assets 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 assets (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 assets amount to \$2.5 million at June 30, 2015 and represent 0.4% of the Total Net Assets shown in Part I, Item 1 at Note 2 – Fair Value Measurements at June 30, 2015.

The increase in the net fair value asset of the Level 3 positions from October 1, 2014 to June 30, 2015, 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 prices 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, 2015.

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, 2015, 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 2014 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 negotiations and other proceedings, on December 6, 2013, Distribution Corporation filed an agreement, also executed by the Department of Public Service and intervenors, extending existing rates through, at a minimum, September 30, 2015. 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 of the agreement. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. A $7.5 million ($4.9 million after-tax) refund provision was passed back to ratepayers during 2014 after the NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014. The agreement also states that nothing in the agreement precludes the parties from meeting to discuss extending the agreement on mutually acceptable terms, and presenting such extension to the NYPSC for approval. On May 22, 2015, Distribution Corporation filed with the NYPSC a Notice of Impending Settlement Discussions stating that settlement discussions would be scheduled in the near future, and that such discussions might include, among other things, the possible extension of the agreement on mutually acceptable terms. Settlement discussions, which under NYPSC regulations must remain confidential, have commenced.

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. Supply Corporation is currently involved in discussions that may lead to the extension of that settlement. Supply Corporation is not barred from filing a general rate case before such date or at any time.

Empire also does not have a 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 requirements.

For further discussion of the Company's environmental exposures, refer to Item 1 at Note 6 — Commitments and Contingencies under the heading "Environmental Matters."

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. In January 2015, the EPA announced its intent to further build upon its April 2012 rules, proposing new rules regulating greenhouse emission from new oil and gas emissions sources. Compliance with these 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. The Company currently complies with California cap-and-trade guidelines, which increases the Company's cost of environmental compliance in its Exploration and Production segment operations. 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.

New Authoritative Accounting and Financial Reporting Guidance

For discussion of the recently issued authoritative accounting and financial reporting guidance, refer to Item 1 at Note 1 — Summary of Significant Accounting Policies under the heading “New Authoritative Accounting and Financial Reporting Guidance.”

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. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;
3. Changes in the price of natural gas or oil;
4. 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;
5. 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;

6. Changes in price differential between similar quantities of natural gas or oil 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. 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;
9. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
10. Uncertainty of oil and gas reserve estimates;
11. Significant differences between the Company's projected and actual production levels for natural gas or oil;
12. 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;
13. Changes in demographic patterns and weather conditions;
14. Changes in the availability, price or accounting treatment of derivative financial instruments;
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 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, 2015.

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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, 2015 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

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.

Item 1A. Risk Factors

The risk factors in Item 1A of the Company’s 2014 Form 10-K, as amended by Item 1A of Part II of the Company's Form 10-Q for the quarter ended March 31, 2015, have not materially changed other than as set forth below. The risk factors presented below supersede the risk factors having the same captions in the 2014 Form 10-K and should otherwise be read in conjunction with all of the risk factors disclosed in the 2014 Form 10-K and the March 31, 2015 Form 10-Q.

The Company is dependent on capital and credit markets to successfully execute its business strategies.

The Company relies upon short-term bank borrowings, commercial paper markets and longer-term capital markets to finance capital requirements not satisfied by cash flow from operations. The Company is dependent on these capital sources to provide capital to its subsidiaries to fund operations, acquire, maintain and develop properties, and execute growth strategies. The availability and cost of credit sources may be cyclical and these capital sources may not remain available to the Company. Turmoil in credit markets may make it difficult for the Company to obtain financing on acceptable terms or at all for working capital, capital expenditures and other investments, or to refinance maturing debt on favorable terms. These difficulties could adversely affect the Company's growth strategies, operations and financial performance. The Company's ability to borrow under its credit facilities and commercial paper agreements, and its ability to issue long-term debt under its indentures, depend on the Company's compliance with its obligations under the facilities, agreements and indentures. Under the Company’s 1974 indenture, at June 30, 2015, the Company is precluded from issuing additional long-term unsecured indebtedness for a period of nine months beginning in October 2015 as a result of the impairments of its oil and gas properties recognized during the nine months ended June 30, 2015. If the Company experiences additional impairments of its oil and gas properties in September 2015 and December 2015, the Company expects to be precluded from issuing incremental long-term debt beyond the nine month period beginning in October 2015. The 1974 indenture would not preclude the Company from issuing new long-term debt to replace maturing long-term debt.

In addition, the Company's short-term bank loans are in the form of floating rate debt or debt that may have rates fixed for very short periods of time, resulting in exposure to interest rate fluctuations in the absence of interest rate hedging transactions. The cost of long-term debt, the interest rates on the Company's short-term bank loans and the ability of the Company to issue commercial paper are affected by its debt credit ratings published by S&P, Moody's Investors Service, Inc. and Fitch Ratings. A downgrade in the Company's credit ratings could increase borrowing costs and negatively impact the availability of capital from banks, commercial paper purchasers and other sources.

Financial accounting requirements regarding exploration and production activities are expected to negatively affect the Company's profitability.

The Company accounts for its exploration and production activities under the full cost method of accounting. Each quarter, the Company must perform a "ceiling test" calculation, comparing the level of its unamortized investment in oil and natural gas properties to the present value of the future net revenue projected to be recovered from those properties according to methods prescribed by the SEC. In determining present value, the Company uses 12-month average prices for oil and natural gas (based on first day of the month prices and adjusted for hedging). If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be "impaired," and the full cost accounting rules require that the investment must be written down to the calculated net present value. Such an instance would require the Company to recognize an immediate expense in that quarter, and its earnings would be reduced. Depending on the magnitude of any decrease in average prices, that charge could be material. For the quarter ended March 31, 2015, the Company recognized a pre-tax impairment charge on its oil and natural gas properties of $120.3 million. For the quarter ended June 30, 2015, the Company recognized a pre-tax impairment charge on its oil and natural gas properties of $588.7

million. Given the potential that oil and natural gas prices could stay at low levels in future months, and the expected loss of significantly higher prices from the 12-month average that will be used in the ceiling test at September 30, 2015 and December 31, 2015, the Company expects to experience significant ceiling test impairments in each of those quarters.

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

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

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

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

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

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

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

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Board and the Ontario Energy Board could affect the viability and profitability of Supply Corporation and Empire projects designed to transport gas from New York into Ontario.

In January 2012, President Obama signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act. The legislation increases civil penalties for pipeline safety violations and addresses matters such as pipeline damage prevention, automatic and remote-controlled shut-off valves, excess flow valves, pipeline integrity management, documentation and testing of maximum allowable operating pressure, and reporting of pipeline accidents. The legislation requires the Pipeline and Hazardous Materials Safety Administration (PHMSA) to issue or revise certain regulations and to conduct various reviews, studies and evaluations. In addition, PHMSA in August 2011 issued an Advance Notice of Proposed Rulemaking regarding pipeline safety. As described in the notice, PHMSA is considering regulations regarding, among other things, the designation of additional high consequence areas along pipelines, minimum requirements for leak detection systems, installation of emergency flow restricting devices, and revision of valve spacing requirements. In May 2015, PHMSA issued a Notice of Proposed Rulemaking regarding proposed amendments to regulations involving plastic pipe used in natural gas systems. As described in the Notice, PHMSA is considering amendments to regulations primarily concerning the incorporation of tracking and traceability provisions, design factor for polyethylene pipe, more stringent mechanical fitting requirements and expanded use of certain thermoplastic pipe material. In addition, in July 2015, PHMSA issued two additional Notices of Proposed Rulemaking, one to require expanded use of excess flow valves for natural gas utilities and the other concerning proposed changes to rules primarily concerning pipeline incident notifications, operator qualifications and pipeline flow reversals. Unrelated to these safety initiatives, the EPA in April 2010 issued an Advance Notice of Proposed Rulemaking reassessing its regulations governing the use and distribution in commerce of PCBs. The EPA had projected that it would issue a Notice of Proposed Rulemaking by April 2013, but it has not done so. If as a result of these or similar new laws or regulations the Company incurs material costs that it is unable to recover fully through rates or otherwise offset, the Company's financial condition, results of operations, and cash flows would be adversely affected.

In the Company 's Exploration and Production segment, various aspects of Seneca's operations are subject to regulation by, among others, the EPA, the U.S. Fish and Wildlife Service, the U.S. Forestry Service, the Bureau of Land Management, the PaDEP, the Pennsylvania Department of Conservation and Natural Resources, the Division of Oil, Gas and Geothermal Resources of the California Department of Conservation; the California Department of Fish and Wildlife, the Oil and Gas Conservation Division of the Kansas Corporation Commission, and in some areas, locally adopted ordinances. Administrative proceedings or increased regulation by these or other agencies could lead to operational delays or restrictions and increased expense for Seneca.

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

On April 1, 2015, the Company issued a total of 3,600 unregistered shares of Company common stock to six non-employee directors of the Company then serving on the Board of Directors of the Company, 600 shares to each such director. On June 11, 2015, the Company issued 132 unregistered shares of Company common stock to Joseph N. Jaggers, who joined the Board that day as a non-employee 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, 2015. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased [a]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or	Maximum Number of Shares That May Yet Be Purchased Under Share Repurchase Plans or Programs [b]

			Programs	
Apr. 1 - 30, 2015	627	$63.09	—	6,971,019
May 1 - 31, 2015	317	$64.44	—	6,971,019
June 1 - 30, 2015	6,502	$61.94	—	6,971,019
Total	7,446	$62.14	—	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, 2015, 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.

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Item 6. Exhibits

Exhibit Number	Description of Exhibit
•	Form of Indemnification Agreement between National Fuel Gas Company and Joseph N. Jaggers, Director (Exhibit 10.1, Form 8-K dated September 18, 2006).
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Twelve Months Ended June 30, 2015 and the Fiscal Years Ended September 30, 2011 through 2014.
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, 2015 and 2014.
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, 2015 and 2014, (ii) the Consolidated Statements of Comprehensive Income for the three and nine months ended June 30, 2015 and 2014, (iii) the Consolidated Balance Sheets at June 30, 2015 and September 30, 2014, (iv) the Consolidated Statements of Cash Flows for the nine months ended June 30, 2015 and 2014 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 7, 2015