NATIONAL FUEL GAS CO
Form 10-Q
August 05, 2016

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, 2016
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, 2016: 84,988,442 shares.

Table of Contents

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	
2015 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2015
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, forward 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

2

Table of Contents

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.

3

Table of Contents

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.

Table of Contents

INDEX Page

• The Company has nothing to report under this item.

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.

Table of Contents

Part I. Financial Information

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

	Three Months Ended June 30,		Nine Months Ended June 30,	
(Thousands of Dollars, Except Per Common Share Amounts)	2016	2015	2016	2015
INCOME				
Operating Revenues:				
Utility and Energy Marketing Revenues	$123,976	$132,422	$540,981	$772,802
Exploration and Production and Other Revenues	158,578	160,256	456,032	532,173
Pipeline and Storage and Gathering Revenues	53,063	47,137	162,930	154,876
	335,617	339,815	1,159,943	1,459,851
Operating Expenses:				
Purchased Gas	23,477	27,038	147,168	344,728
Operation and Maintenance:				
Utility and Energy Marketing	46,616	44,263	151,474	156,724
Exploration and Production and Other	35,427	46,162	123,965	140,564
Pipeline and Storage and Gathering	23,215	20,272	64,324	59,237
Property, Franchise and Other Taxes	20,261	22,717	61,923	68,561
Depreciation, Depletion and Amortization	58,802	79,865	193,300	265,298
Impairment of Oil and Gas Producing Properties	82,658	588,712	915,552	709,060
	290,456	829,029	1,657,706	1,744,172
Operating Income (Loss)	45,161	(489,214)	(497,763)	(284,321)
Other Income (Expense):				
Interest Income	564	327	2,640	1,631
Other Income	1,519	2,066	7,173	4,638
Interest Expense on Long-Term Debt	(28,897)	(22,213)	(88,263)	(66,900)
Other Interest Expense	(1,321)	(1,007)	(3,938)	(3,382)
Income (Loss) Before Income Taxes	17,026	(510,041)	(580,151)	(348,334)
Income Tax Expense (Benefit)	8,740	(216,907)	(251,641)	(156,610)
Net Income (Loss) Available for Common Stock	8,286	(293,134)	(328,510)	(191,724)
EARNINGS REINVESTED IN THE BUSINESS				
Balance at Beginning of Period	699,399	1,650,840	1,103,200	1,614,361
	707,685	1,357,706	774,690	1,422,637
Dividends on Common Stock	(34,404)	(33,388)	(101,409)	(98,319)
Balance at June 30	$673,281	$1,324,318	$673,281	$1,324,318
Earnings Per Common Share:				
Basic:				
Net Income (Loss) Available for Common Stock	$0.10	$(3.47)	$(3.87)	$(2.27)

Diluted:				
Net Income (Loss) Available for Common Stock	$0.10	$(3.44)	$(3.87)	$(2.25)
Weighted Average Common Shares Outstanding:				
Used in Basic Calculation	84,917,664	84,453,602	84,791,447	84,326,182
Used in Diluted Calculation	85,470,216	85,248,281	84,791,447	85,237,514
Dividends Per Common Share:				
Dividends Declared	$0.405	$0.395	$1.195	$1.165

See Notes to Condensed Consolidated Financial Statements

6

Table of Contents

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

	Three Months Ended June 30,		Nine Months Ended June 30,	
(Thousands of Dollars)	2016	2015	2016	2015
Net Income (Loss) Available for Common Stock	$8,286	$(293,134)	$(328,510)	$(191,724)
Other Comprehensive Income (Loss), Before Tax:				
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	376	90	(266)	(56)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(70,363)	(9,483)	28,777	295,511
Reclassification Adjustment for Realized (Gains) Losses on Securities Available for Sale in Net Income	—	—	(388)	—
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(58,373)	(50,875)	(176,779)	(129,270)
Other Comprehensive Income (Loss), Before Tax	(128,360)	(60,268)	(148,656)	166,185
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	122	33	(85)	(27)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(29,521)	(4,060)	5,345	124,792
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Securities Available for Sale in Net Income	—	—	(163)	—
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	(24,514)	(21,800)	(68,120)	(54,807)
Income Taxes – Net	(53,913)	(25,827)	(63,023)	69,958
Other Comprehensive Income (Loss)	(74,447)	(34,441)	(85,633)	96,227
Comprehensive Income (Loss)	$(66,161)	$(327,575)	$(414,143)	$(95,497)

See Notes to Condensed Consolidated Financial Statements

Table of Contents

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

	June 30, 2016	September 30, 2015
(Thousands of Dollars)		
ASSETS		
Property, Plant and Equipment	$9,460,444	$ 9,261,323
Less - Accumulated Depreciation, Depletion and Amortization	5,012,690	3,929,428
	4,447,754	5,331,895
Current Assets		
Cash and Temporary Cash Investments	105,567	113,596
Hedging Collateral Deposits	3,008	11,124
Receivables – Net of Allowance for Uncollectible Accounts of $27,413 and $29,029, Respectively	140,911	105,004
Unbilled Revenue	14,604	20,746
Gas Stored Underground	15,944	34,252
Materials and Supplies - at average cost	33,039	30,414
Unrecovered Purchased Gas Costs	933	—
Other Current Assets	47,118	60,665
	361,124	375,801
Other Assets		
Recoverable Future Taxes	172,456	168,214
Unamortized Debt Expense	1,821	2,218
Other Regulatory Assets	269,343	278,227
Deferred Charges	17,968	15,129
Other Investments	111,385	92,990
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	27,158	24,459
Fair Value of Derivative Financial Instruments	126,596	270,363
Other	116	167
	732,319	857,243
Total Assets	$5,541,197	$ 6,564,939

See Notes to Condensed Consolidated Financial Statements

8

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

	June 30, 2016	September 30, 2015
(Thousands of Dollars)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued And Outstanding – 84,948,691 Shares and 84,594,383 Shares, Respectively	$84,949	$ 84,594
Paid in Capital	761,673	744,274
Earnings Reinvested in the Business	673,281	1,103,200
Accumulated Other Comprehensive Income	7,739	93,372
Total Comprehensive Shareholders' Equity	1,527,642	2,025,440
Long-Term Debt, Net of Unamortized Discount and Debt Issuance Costs	2,085,686	2,084,009
Total Capitalization	3,613,328	4,109,449
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	—
Current Portion of Long-Term Debt	—	—
Accounts Payable	86,487	180,388
Amounts Payable to Customers	35,441	56,778
Dividends Payable	34,404	33,415
Interest Payable on Long-Term Debt	28,985	36,200
Customer Advances	38	16,236
Customer Security Deposits	16,094	16,490
Other Accruals and Current Liabilities	72,759	96,557
Fair Value of Derivative Financial Instruments	2,133	10,076
	276,341	446,140
Deferred Credits		
Deferred Income Taxes	807,955	1,137,962
Taxes Refundable to Customers	91,452	89,448
Unamortized Investment Tax Credit	470	731
Cost of Removal Regulatory Liability	191,217	184,907
Other Regulatory Liabilities	102,018	108,617
Pension and Other Post-Retirement Liabilities	222,756	202,807
Asset Retirement Obligations	114,804	156,805
Other Deferred Credits	120,856	128,073
	1,651,528	2,009,350
Commitments and Contingencies (Note 6)	—	—
Total Capitalization and Liabilities	$5,541,197	$ 6,564,939

See Notes to Condensed Consolidated Financial Statements

9

Table of Contents

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

(Thousands of Dollars)	Nine Months Ended June 30, 2016	2015
OPERATING ACTIVITIES		
Net Loss Available for Common Stock	$(328,510)	$(191,724)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:		
Impairment of Oil and Gas Producing Properties	915,552	709,060
Depreciation, Depletion and Amortization	193,300	265,298
Deferred Income Taxes	(269,248)	(198,116)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(1,786)	(9,064)
Stock-Based Compensation	3,138	8,383
Other	9,685	7,329
Change in:		
Hedging Collateral Deposits	8,116	(8,367)
Receivables and Unbilled Revenue	(7,756)	22,175
Gas Stored Underground and Materials and Supplies	15,683	20,259
Unrecovered Purchased Gas Costs	(933)	—
Other Current Assets	15,334	14,367
Accounts Payable	(53,687)	11,153
Amounts Payable to Customers	(21,337)	11,097
Customer Advances	(16,198)	(18,961)
Customer Security Deposits	(396)	2,568
Other Accruals and Current Liabilities	3,375	13,794
Other Assets	3,775	1,124
Other Liabilities	(8,152)	52,261
Net Cash Provided by Operating Activities	459,955	712,636
INVESTING ACTIVITIES		
Capital Expenditures	(481,781)	(718,965)
Net Proceeds from Sale of Oil and Gas Producing Properties	115,235	—
Other	(11,163)	(1,065)
Net Cash Used in Investing Activities	(377,709)	(720,030)
FINANCING ACTIVITIES		
Changes in Notes Payable to Banks and Commercial Paper	—	(85,600)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	1,786	9,064
Net Proceeds from Issuance of Long-Term Debt	—	445,662
Dividends Paid on Common Stock	(100,419)	(97,330)
Net Proceeds from Issuance of Common Stock	8,358	8,743
Net Cash (Used in) Provided by Financing Activities	(90,275)	280,539
Net Increase (Decrease) in Cash and Temporary Cash Investments	(8,029)	273,145
Cash and Temporary Cash Investments at October 1	113,596	36,886
Cash and Temporary Cash Investments at June 30	$105,567	$310,031

Supplemental Disclosure of Cash Flow Information		
Non-Cash Investing Activities:		
Non-Cash Capital Expenditures	$44,380	$122,587
Receivable from Sale of Oil and Gas Producing Properties	$22,081	$—

See Notes to Condensed Consolidated Financial Statements

10

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 Company uses proportionate consolidation when accounting for drilling arrangements related to oil and gas producing properties accounted for under the full cost method of accounting.

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.

Reclassification. Due to the adoption of the authoritative guidance regarding the presentation of deferred income taxes, certain prior year amounts have been reclassified to conform with current year presentation. The Company reclassified Deferred Income Taxes of $137.2 million previously shown as Current Assets in the Company's 2015 Form 10-K to Deferred Income Taxes shown as Deferred Credits on the Consolidated Balance Sheet at September 30, 2015.

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, 2015, 2014 and 2013 that are included in the Company's 2015 Form 10-K. The consolidated financial statements for the year ended September 30, 2016 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, 2016 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2016. 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. In the Utility segment, gas stored underground is carried at lower of cost or market, on a LIFO method. Gas stored underground 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 $6.5 million at June 30, 2016, 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 $130.9 million and $176.3 million at June 30, 2016 and September 30, 2015, 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.

Table of Contents

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. The book value of the oil and gas properties exceeded the ceiling at June 30, 2016 as well as March 31, 2016 and December 31, 2015. As such, the Company recognized pre-tax impairment charges of $82.7 million and $915.6 million for the quarter and nine months ended June 30, 2016, respectively. Deferred income tax benefits of $34.8 million and $384.6 million related to the impairment charges were also recognized for the quarter and nine months ended June 30, 2016, respectively. In adjusting estimated future cash flows for hedging under the ceiling test at June 30, 2016, March 31, 2016 and December 31, 2015, estimated future net cash flows were increased by $262.9 million, $252.1 million and $253.7 million, respectively.

On December 1, 2015, Seneca and IOG - CRV Marcellus, LLC (IOG), an affiliate of IOG Capital, LP, and funds managed by affiliates of Fortress Investment Group, LLC, executed a joint development agreement that allows IOG to participate in the development of certain oil and gas interests owned by Seneca in Elk, McKean and Cameron Counties, Pennsylvania. On June 13, 2016, Seneca and IOG executed an extension of the joint development agreement. Under the terms of the extended agreement, Seneca and IOG will jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. The extended joint development agreement gives IOG the option to participate in a 7-well Marcellus pad that is expected to be completed before December 31, 2017, which, if exercised, would increase the maximum number of joint development wells to 82. Under the original joint development agreement, IOG had committed to develop 42 Marcellus wells. IOG will hold an 80% working interest in all of the joint development wells. In total, IOG is expected to fund approximately $325 million for its 80% working interest in the 75 joint development wells. As of June 30, 2016, Seneca had received $115.2 million of cash and had recorded a $22.1 million receivable in recognition of IOG funding that is due to Seneca for costs previously incurred to develop a portion of the 75 joint development wells. The cash proceeds and receivable were recorded by Seneca as a $137.3 million reduction of property, plant and equipment. As the fee-owner of the property's mineral rights, Seneca retains a 7.5% royalty interest and the remaining 20% working interest (26% net revenue interest) in 56 of the joint development wells. In the remaining 19 wells, Seneca retains a 20% working and net revenue interest. Seneca's working interest under the agreement will increase to 85% after IOG achieves a 15% internal rate of return.

Asset Retirement Obligations. On June 30, 2016, Seneca sold the majority of its Upper Devonian wells in Pennsylvania. While the proceeds from the sale were not significant, it did result in a $58.4 million reduction of its Asset Retirement Obligation at June 30, 2016. The table below is a reconciliation of the asset retirement obligation from September 30, 2015 to June 30, 2016 (in thousands):

	Nine Months Ended June 30, 2016

Balance at Beginning of Year	$156,805
Liabilities Incurred	—
Revisions of Estimates	17,845
Liabilities Settled	(66,756)
Accretion Expense	6,910
Balance at June 30, 2016	$114,804

12

Table of Contents

Accumulated Other Comprehensive Income (Loss). The components of Accumulated Other Comprehensive Income (Loss) and changes for the quarter and nine months ended June 30, 2016 and 2015, 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, 2016				
Balance at April 1, 2016	$ 146,671	$ 5,309	$ (69,794)	$ 82,186
Other Comprehensive Gains and Losses Before Reclassifications	(40,842)	254	—	(40,588)
Amounts Reclassified From Other Comprehensive Income (Loss)	(33,859)	—	—	(33,859)
Balance at June 30, 2016	$ 71,970	$ 5,563	$ (69,794)	$ 7,739
Nine Months Ended June 30, 2016				
Balance at October 1, 2015	$ 157,197	$ 5,969	$ (69,794)	$ 93,372
Other Comprehensive Gains and Losses Before Reclassifications	23,432	(181)	—	23,251
Amounts Reclassified From Other Comprehensive Income (Loss)	(108,659)	(225)	—	(108,884)
Balance at June 30, 2016	$ 71,970	$ 5,563	$ (69,794)	$ 7,739
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

Table of Contents

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, 2016 and 2015 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				Affected Line Item in the Statement Where Net Income (Loss) is Presented
	Three Months Ended June 30,		Nine Months Ended June 30,		
	2016	2015	2016	2015	
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:					
Commodity Contracts	$58,354	$50,878	$172,596	$124,386	Operating Revenues
Commodity Contracts	70	(3)	4,520	4,884	Purchased Gas
Foreign Currency Contracts	(51)	—	(337)	—	Operation and Maintenance Expense
Gains (Losses) on Securities Available for Sale	—	—	388	—	Other Income
	58,373	50,875	177,167	129,270	Total Before Income Tax
	(24,514)	(21,800)	(68,283)	(54,807)	Income Tax Expense
	$33,859	$29,075	$108,884	$74,463	Net of Tax

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

	At June 30, 2016	At September 30, 2015
Prepayments	$11,963	$ 10,743
Prepaid Property and Other Taxes	10,574	13,709
Federal Income Taxes Receivable	5,830	—
State Income Taxes Receivable	2,237	—
Fair Values of Firm Commitments	3,227	15,775
Regulatory Assets	13,287	20,438
	$47,118	$ 60,665

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

	At June 30, 2016	At September 30, 2015
Accrued Capital Expenditures	$19,287	$ 53,652
Regulatory Liabilities	22,138	5,346
Reserve for Gas Replacement	6,490	—
Federal Income Taxes Payable	—	5,686
State Income Taxes Payable	—	1,170
Other	24,844	30,703
	$72,759	$ 96,557

Earnings Per Common Share. Basic earnings per common share is computed by dividing income or loss 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. As the Company recognized a net loss for the nine months ended June 30, 2016, the aforementioned securities, amounting to 414,092 shares, were not recognized in the diluted earnings per share calculation for the nine months ended June 30, 2016. For the quarter ended June 30, 2016 and for the quarter and nine months ended June 30, 2015, 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 346,090 shares excluded as being antidilutive for the quarter ended June 30, 2016. There were 180,065 and 2,948 shares excluded as being antidilutive for the quarter and nine months ended June 30, 2015, respectively.

Stock-Based Compensation. The Company granted 309,996 performance shares during the nine months ended June 30, 2016. The weighted average fair value of such performance shares was $30.71 per share for the nine months ended June 30, 2016. 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, 2016 must meet a performance goal related to relative return on capital over the performance cycle of October 1, 2015 to September 30, 2018. 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, 2016 must meet a performance goal related to relative total shareholder return over the performance cycle of October 1, 2015 to September 30, 2018. 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 99,843 non-performance based restricted stock units during the nine months ended June 30, 2016. The weighted average fair value of such non-performance based restricted stock units was $35.57 per share for the nine months ended June 30, 2016. 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, 2016.

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

Table of Contents

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 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.

In November 2015, the FASB issued authoritative guidance simplifying the presentation of deferred income taxes. The authoritative guidance requires entities with a classified balance sheet to present all deferred tax assets and liabilities as noncurrent. The Company early adopted this guidance at December 31, 2015 on a retrospective basis.

In January 2016, the FASB issued authoritative guidance regarding the recognition and measurement of financial assets and liabilities. The authoritative guidance primarily affects the accounting for equity investments, financial liabilities under the fair value option and the presentation and disclosure requirements for financial instruments. All equity investments in unconsolidated entities will be measured at fair value through earnings rather than through other comprehensive income. This authoritative guidance will 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.

In February 2016, the FASB issued authoritative guidance requiring organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by all leases, regardless of whether they are considered to be capital leases or operating leases. The FASB’s previous authoritative guidance required organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by capital leases while excluding operating leases from balance sheet recognition. The new authoritative guidance will be effective as of the Company’s first quarter of fiscal 2020, with early adoption permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements.

In March 2016, the FASB issued authoritative guidance simplifying several aspects of the accounting for stock-based compensation. Among other things, the revised guidance specifies that the difference between the compensation recognized for financial reporting purposes and the deduction allowed for tax purposes (excess tax benefit or deficiency) shall be recognized as income tax expense or benefit in the income statement, as opposed to the current treatment where this difference is recognized as additional paid-in capital in the balance sheet. For statement of cash flows purposes, the revised guidance specifies that the excess tax benefit shall be classified along with other income tax cash flows as an item impacting cash flow from operating activities. The current guidance separates the excess tax benefit from other income tax cash flows and classifies the excess tax benefit as an item impacting cash flow from financing activities. The new 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.

Table of Contents

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, 2016 and September 30, 2015. 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, 2016				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
Assets:					
Cash Equivalents – Money Market Mutual Funds	$81,255	$—	$ —	$ —	$81,255
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	2,991	—	—	(2,957)	34
Over the Counter Swaps – Gas and Oil	—	137,774	—	(8,990)	128,784
Foreign Currency Contacts	—	—	—	(2,222)	(2,222)
Other Investments:					
Balanced Equity Mutual Fund	36,964	—	—	—	36,964
Fixed Income Mutual Fund	31,279	—	—	—	31,279
Common Stock – Financial Services Industry	3,813	—	—	—	3,813
Hedging Collateral Deposits	3,008	—	—	—	3,008
Total	$159,310	$137,774	$ —	$ (14,169)	$282,915
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$2,957	$—	$ —	$ (2,957)	$—
Over the Counter Swaps – Gas and Oil	—	10,694	—	(8,990)	1,704
Foreign Currency Contracts	—	2,222	—	(2,222)	—
Total	$2,957	$12,916	$ —	$ (14,169)	$1,704
Total Net Assets/(Liabilities)	$156,353	$124,858	$ —	$ —	$281,211

Recurring Fair Value Measures	At fair value as of September 30, 2015				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
Assets:					
Cash Equivalents – Money Market Mutual Funds	$92,196	$—	$—	$ —	$92,196
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	6,373	—	—	(6,373)	—
Over the Counter Swaps – Gas and Oil	—	272,335	1,791	(808)	273,318
Foreign Currency Contracts	—	—	—	(2,955)	(2,955)
Other Investments:					
Balanced Equity Mutual Fund	34,884	—	—	—	34,884
Fixed Income Mutual Fund	8,004	—	—	—	8,004
Common Stock – Financial Services Industry	4,318	—	—	—	4,318
Other Common Stock	450	—	—	—	450
Hedging Collateral Deposits	11,124	—	—	—	11,124
Total	$157,349	$272,335	$1,791	$ (10,136)	$421,339
Liabilities:					
Derivative Financial Instruments:					

Commodity Futures Contracts – Gas	$15,276	$—	$—	$ (6,373)	$8,903
Over the Counter Swaps – Gas and Oil	—	1,981	—	(808)	1,173
Foreign Currency Contracts	—	2,955	—	(2,955)	—
Total	$15,276	$4,936	$—	$ (10,136)	$10,076
Total Net Assets/(Liabilities)	$142,073	$267,399	$1,791	$ —	$411,263

(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.

17

Table of Contents

Derivative Financial Instruments

At June 30, 2016 and September 30, 2015, 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 $3.0 million at June 30, 2016 and $11.1 million at September 30, 2015, 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, 2016 and September 30, 2015 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 is determined using the market approach based on observable market transactions of forward Canadian currency rates. The derivative financial instruments reported in Level 3 consist of a small portion of the crude oil price swap agreements used in the Company’s Exploration and Production segment at September 30, 2015 that settled prior to December 31, 2015. The fair value of the Level 3 crude oil price swap agreements was 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 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, 2016, 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's (assuming the derivative is in a gain position) or the Company’s (assuming the derivative is in a loss position) 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 quarter ended June 30, 2015 and the nine months ended June 30, 2016 and 2015, respectively. For the quarters and nine months ended June 30, 2016 and June 30, 2015, 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			
	October 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, 2016
Derivative Financial Instruments[2]	$ 1,791	$ (2,002)[1]	$ 211	$ —	$ —

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the nine months ended June 30, 2016.

(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, 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.

18

Table of Contents

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.

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, 2016		September 30, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$2,085,686	$2,207,673	$2,084,009	$2,129,558

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, a fixed income 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 and fixed income securities. The values of the insurance contracts amounted to $39.3 million at June 30, 2016 and $45.3 million at September 30, 2015. The fair value of the equity mutual fund was $37.0 million at June 30, 2016 and $34.9 million at September 30, 2015. The gross unrealized gain on this equity mutual fund was $6.6 million at June 30, 2016 and $6.5 million at September 30, 2015. The fair value of the fixed income mutual fund was $31.3 million at June 30, 2016 and $8.0 million at September 30, 2015.

The gross unrealized gain on this fixed income mutual fund was $0.1 million at June 30, 2016. The fair value of the stock of an insurance company was $3.8 million at June 30, 2016 and $4.3 million at September 30, 2015. The gross unrealized gain on this stock was $2.1 million at June 30, 2016 and $2.6 million at September 30, 2015. 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

Table of Contents

contracts and swaps to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in value of natural gas held in storage. These instruments are accounted for as fair value hedges. The duration of the Company's combined cash flow and fair value commodity hedges does not typically exceed 5 years while the foreign currency forward contracts do not exceed ten 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, 2016 and September 30, 2015. Substantially all of the derivative financial instruments reported on those line items relate to commodity contracts and a small portion relates to foreign currency forward 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 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, 2016, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	178.0	Bcf (short positions)
Natural Gas	1.7	Bcf (long positions)
Crude Oil	1,722,000	Bbls (short positions)

As of June 30, 2016, the Company was hedging a total of $81.5 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts (long positions).

As of June 30, 2016, the Company had $124.2 million ($72.0 million after tax) of net hedging gains included in the accumulated other comprehensive income balance. It is expected that $93.2 million ($54.0 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 are recorded in earnings.

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

Table of Contents

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended June 30, 2016 and 2015 (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 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 Three 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 Three Months Ended June 30,	
	2016	2015		2016	2015		2016	2015
Commodity Contracts	$(68,914)	$(8,845)	Operating Revenue	$58,354	$50,878	Operating Revenue	$ 87	$ 159
Commodity Contracts	$(921)	$(84)	Purchased Gas	$70	$(3)	Not Applicable	$ —	$ —
Foreign Currency Contracts	$(528)	$(554)	Operation and Maintenance Expense	$(51)	$—	Not Applicable	$ —	$ —
Total	$(70,363)	$(9,483)		$58,373	$50,875		$ 87	$ 159

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Nine Months Ended June 30, 2016 and 2015 (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,	
	2016	2015		2016	2015		2016	2015
Commodity Contracts	$27,304	$291,749	Operating Revenue	$172,596	$124,386	Operating Revenue	$255	$3,088
Commodity Contracts	$1,078	$4,316	Purchased Gas	$4,520	$4,884	Not Applicable	$—	$—
Foreign Currency Contracts	$395	$(554)	Operation and Maintenance Expense	$(337)	$—	Not Applicable	$—	$—
Total	$28,777	$295,511		$176,779	$129,270		$255	$3,088

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, 2016, the Company’s Energy Marketing segment had fair value hedges covering approximately 13.3 Bcf (12.7 Bcf of fixed price sales commitments, 0.1 Bcf of fixed price purchase commitments and 0.5 Bcf of commitments related to the withdrawal of storage gas). For derivative instruments that are designated

21

and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

Derivatives in Fair Value Hedging Relationships	Location of Gain or (Loss) on Derivative and Hedged Item Recognized in the Consolidated Statement of Income	Amount of Gain or (Loss) on Derivative Recognized in the Consolidated Statement of Income for the Nine Months Ended June 30, 2016 (In Thousands)	Amount of Gain or (Loss) on the Hedged Item Recognized in the Consolidated Statement of Income for the Nine Months Ended June 30, 2016 (In Thousands)
Commodity Contracts	Operating Revenues	$ 13,628	$ (13,628)
Commodity Contracts	Purchased Gas	$ (512)	$ 512
		$ 13,116	$ (13,116)

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 and applicable foreign currency forward contracts with seventeen counterparties of which fourteen are in a net gain position. On average, the Company had $9.0 million of credit exposure per counterparty in a gain position at June 30, 2016. The maximum credit exposure per counterparty in a gain position at June 30, 2016 was $25.8 million. As of June 30, 2016, no collateral was received from the counterparties by the Company. The Company's gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral, nor had the counterparties' credit ratings declined to levels at which the counterparties were required to post collateral.

As of June 30, 2016, thirteen of the seventeen counterparties to the Company’s outstanding derivative instrument contracts (specifically the over-the-counter swaps and applicable foreign currency forward contracts) 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, 2016, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $81.6 million according to the Company’s internal model (discussed in Note 2 — Fair Value Measurements). For its over-the-counter swap agreements and foreign currency forward contracts, no hedging collateral deposits were required to be posted by the Company at June 30, 2016.

For its exchange traded futures contracts, the Company was required to post $3.0 million in hedging collateral deposits as of June 30, 2016. 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.

Table of Contents

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,	
	2016	2015
Current Income Taxes		
Federal	$(686)	$27,311
State	18,293	14,195
Deferred Income Taxes		
Federal	(184,419)	(134,369)
State	(84,829)	(63,747)
	(251,641)	(156,610)
Deferred Investment Tax Credit	(261)	(311)
Total Income Taxes	$(251,902)	$(156,921)
Presented as Follows:		
Other Income	(261)	(311)
Income Tax Expense (Benefit)	(251,641)	(156,610)
Total Income Taxes	$(251,902)	$(156,921)

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,	
	2016	2015
U.S. Income (Loss) Before Income Taxes	$(580,412)	$(348,645)
Income Tax Expense (Benefit), Computed at U.S. Federal Statutory Rate of 35%	$(203,144)	$(122,026)
State Income Taxes (Benefit)	(43,248)	(32,209)
Miscellaneous	(5,510)	(2,686)
Total Income Taxes	$(251,902)	$(156,921)

As a result of a settlement reached during the quarter ended June 30, 2016, the Company has reduced the balance of unrecognized tax benefits by $3.1 million, of which $0.8 million was recorded as an income tax benefit. As of June 30, 2016, the entire balance of unrecognized tax benefits would favorably impact the effective tax rate, if recognized.

Note 5 - Capitalization

Common Stock. During the nine months ended June 30, 2016, the Company issued 172,574 original issue shares of common stock as a result of stock option and SARs exercises and 67,733 original issue shares of common stock for restricted stock units that vested. In addition, the Company issued 102,139 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 92,756 original issue shares of common stock for the

Company's 401(k) plans. The Company also issued 13,384 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, 2016. 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, 2016, 59,278 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law. There were also 35,000 restricted stock award shares forfeited during the nine months ended June 30, 2016.

Current Portion of Long-Term Debt. None of the Company's long-term debt at June 30, 2016 will mature within the following twelve-month period.

Note 6 - Commitments and Contingencies

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory 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, 2016, 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 $4.0 million. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 11 years.

The Company's estimated liability for clean-up costs discussed above includes a $2.9 million estimated liability related to the remediation of 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 was completed, and active remedial work has also been completed. Restoration work is substantially complete.

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 2015 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 2015 Form 10-K. A listing of segment assets at June 30, 2016 and September 30, 2015 is shown in the tables below.

Table of Contents

Quarter Ended June 30, 2016 (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	$156,835	$52,998	$65	$106,568	$17,408	$333,874	$1,508	$235	$335,617
Intersegment Revenues	$—	$22,795	$25,417	$1,729	$231	$50,172	$—	$(50,172)	$—
Segment Profit: Net Income (Loss)	$(19,165)	$17,323	$9,473	$2,179	$(590)	$9,220	$430	$(1,364)	$8,286

Nine Months Ended June 30, 2016 (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	$452,583	$162,627	$303	$463,154	$77,827	$1,156,494	$2,775	$674	$1,159,943
Intersegment Revenues	$—	$68,272	$65,601	$10,757	$855	$145,485	$—	$(145,485)	$—
Segment Profit: Net Income (Loss)	$(469,586)	$59,794	$21,962	$52,745	$4,117	$(330,968)	$595	$1,863	$(328,510)

(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, 2016	$1,436,632	$1,627,756	$520,440	$1,904,880	$65,305	$5,555,013	$76,846	$(90,662)	$5,541,197
At September 30, 2015	$2,439,801	$1,590,525	$444,358	$1,934,730	$90,676	$6,500,090	$77,350	$(12,501)	$6,564,939

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)

Table of Contents

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,	2016	2015	2016	2015
Service Cost	$2,928	$3,012	$583	$673
Interest Cost	10,579	10,304	5,096	4,821
Expected Return on Plan Assets	(14,842)	(14,904)	(7,883)	(8,522)
Amortization of Prior Service Cost (Credit)	308	46	(228)	(478)
Amortization of Losses	8,062	9,032	1,382	1,037
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	14	88	3,936	4,739
Net Periodic Benefit Cost	$7,049	$7,578	$2,886	$2,270

	Retirement Plan		Other Post-Retirement Benefits	
Nine Months Ended June 30,	2016	2015	2016	2015
Service Cost	$8,783	$9,036	$1,748	$2,019
Interest Cost	31,736	30,913	15,289	14,464
Expected Return on Plan Assets	(44,527)	(44,712)	(23,651)	(25,566)
Amortization of Prior Service Cost (Credit)	925	137	(684)	(1,435)
Amortization of Losses	24,186	27,097	4,147	3,111
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	7,531	8,434	14,657	17,055
Net Periodic Benefit Cost	$28,634	$30,905	$11,506	$9,648

(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, 2016, the Company contributed $4.0 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $2.3 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2016, the Company expects to make no additional contributions to the Retirement Plan. In the remainder of 2016, the Company expects to contribute approximately $0.3 million to its VEBA trusts and 401(h) accounts.

Note 9 – Regulatory Matters

On April 28, 2016, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by approximately $41.7 million. Distribution

Corporation explained in the filing that its request for rate relief was necessitated by a revenue requirement driven primarily by rate base growth, higher operating expense and higher depreciation expense that are not reflected in current rates, among other things. The rate filing includes a proposal for system infrastructure modernization that includes the acceleration of Distribution Corporation's replacement of certain gas mains, which are of a type generically classified by the NYPSC as "leak prone pipe". The NYPSC may accept, reject or modify the Company's filing. In June of 2016, the administrative law judge assigned to the case adopted a schedule that requires Staff and intervenor testimony to be filed by August 26, 2016, and establishes the commencement of an evidentiary hearing on October 5, 2016. Assuming standard procedure, new rates, if accepted, would become effective on or about April 1, 2017. The outcome of the proceeding cannot be ascertained at this time.

Table of Contents

FERC Rate Proceedings

Supply Corporation's current rate settlement requires a rate case filing no later than December 31, 2019 and prohibits any party from seeking to initiate a rate case proceeding before September 30, 2017.

By order dated January 21, 2016, the FERC began a NGA Section 5 rate review of Empire's rates. As required by that order, Empire filed a Cost and Revenue Study on April 5, 2016. On May 25, 2016, Empire reached a settlement in principle on this matter that would, among other things, reduce certain of Empire’s maximum transportation rates over a 14-month period, which, based on current contracts, is estimated to reduce Empire’s revenues on a yearly basis by between $3 million to $4 million. The settlement also reduces Empire’s depreciation rate from 2.5% to 2%. In addition, the settlement provides an annual revenue sharing mechanism, pursuant to which non-expansion transportation revenues exceeding $73.5 million are shared on a tiered basis. Under the settlement, Empire will be required to make a general rate filing no later than July 1, 2021. On July 22, 2016, Empire filed the settlement at the FERC and is awaiting approval. The settlement is not expected to have a material impact on the Company’s financial condition.

Table of Contents

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, with assets centered in western New York and Pennsylvania, being utilized for, and benefiting from, the production and transportation of natural gas from the Appalachian basin. Current development activities are focused in the Marcellus Shale. 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.

The Company continues to develop its natural gas reserves in the Marcellus Shale, but at a slower pace than previous years given the current low commodity price environment. The Marcellus Shale is 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 785,000 net acres within the Marcellus Shale area, with a majority of the interests held in fee, carrying no royalty and no lease expirations. In March 2016, the Company reduced its Marcellus Shale development program to one drilling rig, down from three drilling rigs at the beginning of fiscal 2016. Capital expenditures in the Exploration and Production segment are expected to be approximately $130 million during fiscal 2016, which is net of a $137.3 million reimbursement from IOG CRV-Marcellus, LLC (IOG) under a joint development agreement for Marcellus Shale natural gas assets located in Elk, McKean and Cameron counties in north-central Pennsylvania. The initial joint development agreement with IOG was executed on December 1, 2015 and subsequently extended on June 13, 2016. Under the terms of the extended agreement, Seneca and IOG will jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. The extended joint development agreement gives IOG the option to participate in a 7-well Marcellus pad that is expected to be completed before December 31, 2017, which, if exercised, would increase the maximum number of joint development wells to 82. Under the original joint development agreement, IOG had committed to develop 42 Marcellus wells. IOG will hold an 80% working interest in all of the joint development wells. In total, IOG is expected to fund approximately $325 million for its 80% working interest in the 75 joint development wells. As the fee-owner of the property's mineral rights, Seneca retains a 7.5% royalty interest and the remaining 20% working interest (26% net revenue interest) in 56 of the joint development wells. In the remaining 19 wells, Seneca retains a 20% working and net revenue interest. Seneca's working interest under the agreement will increase to 85% after IOG achieves a 15% internal rate of return.

On June 30, 2016, Seneca sold the majority of its Upper Devonian wells in Pennsylvania. While the proceeds from the sale were not significant, it did result in a $58.4 million reduction of its Asset Retirement Obligation at June 30, 2016.

Given the slower development pace in the Exploration and Production segment, capital expenditures in the Pipeline and Storage segment and the Gathering segment are expected to be lower than originally forecasted for fiscal 2016. Pipeline and Storage segment capital expenditures are expected to be approximately $135 million while Gathering segment capital expenditures are expected to be approximately $60 million. The target in-service date for the Northern Access 2016 project is November 1, 2017.

While the Company recorded earnings of $8.3 million during the quarter ended June 30, 2016, the nine months ended June 30, 2016 showed a loss of $328.5 million. The Company's Exploration and Production segment experienced impairment charges in both periods, $82.7 million ($47.9 million after-tax) during the quarter ended June 30, 2016, and $915.6 million ($531.0 million after-tax) during the nine months ended June 30, 2016. 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 over the previous twelve months, the book value of the Company’s oil and gas properties exceeded the ceiling at December 31, 2015, March 31, 2016 and June 30, 2016, resulting in the impairment charges mentioned above. Given the current commodity price environment, the Company expects to record an additional significant ceiling test impairment during the quarter ended September 30, 2016. 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.

Table of Contents

Under the Company's existing 1974 indenture covenants, given the significant ceiling test impairments recorded during the year ended September 30, 2015, the quarters ended December 31, 2015, March 31, 2016 and June 30, 2016, and an expected impairment during the quarter ended September 30, 2016, the Company expects to be precluded from issuing additional long-term unsecured indebtedness until the second half of fiscal 2017. However, with the reduction in forecasted capital expenditures discussed above, the Company does not anticipate a need for the issuance of additional long-term debt during the remainder of fiscal 2016. The Company expects to use cash from operations and, if necessary, short-term borrowings to meet its capital expenditure needs for the remainder of fiscal 2016 and much of fiscal 2017. The Company does not have any long-term debt maturing until fiscal 2018. The 1974 indenture would not preclude the Company from issuing new long-term debt to replace maturing long-term debt.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to "Critical Accounting Estimates" in Item 7 of the Company's 2015 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 December 31, 2015 and March 31, 2016 as well as June 30, 2016, resulting in cumulative impairment charges of $915.6 million ($531.0 million after-tax) for the nine months ended June 30, 2016. The impairment charge for the quarter ended June 30, 2016 was $82.7 million ($47.9 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, 2016, based on posted Midway Sunset prices, was $37.67 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, 2016, based on the quoted Henry Hub spot price for natural gas, was $2.24 per MMBtu. (Note – because actual pricing of the Company's various producing properties varies depending on their location and hedging, the actual 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, 2016.) The following table illustrates the sensitivity of the ceiling test calculation to commodity price changes, specifically showing the additional impairment that the Company would have recorded at June 30, 2016 if natural gas prices were $0.25 per MMBtu lower than the average used at June 30, 2016, the additional impairment the Company would have recorded at June 30, 2016 if crude oil prices were $5 per Bbl lower than the average used at June 30, 2016, and the additional impairment that the Company would have recorded at June 30, 2016 if both natural gas prices and crude oil prices were $0.25 per MMBtu and $5 per Bbl lower than the average prices used at June 30, 2016 (all amounts are presented after-tax). 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.

Ceiling Testing Sensitivity to Commodity Price Changes

(Millions)	$0.25/MMBtu Decrease in Natural Gas Prices	$5.00/Bbl Decrease in	$0.25/MMBtu Decrease in Natural Gas Prices

		Crude Oil Prices	and $5.00/Bbl Decrease in Crude Oil Prices
Calculated Impairment under Sensitivity Analysis	$ 161.0	$ 86.9	$ 199.4
Actual Impairment Recorded at June 30, 2016	47.9	47.9	47.9
Additional Impairment	$ 113.1	$ 39.0	$ 151.5

Looking ahead, the first day of the month Midway Sunset price for crude oil in July 2016 was $41.41 per Bbl. The first day of the month Henry Hub spot price for natural gas in July 2016 was $2.90 per MMBtu. While the July 2016 prices are higher than the 12-month average prices used in the ceiling test at June 30, 2016, the Company still expects to experience a significant ceiling test impairment in the quarter ended September 30, 2016. 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 2015 Form 10-K.

Table of Contents

RESULTS OF OPERATIONS

Earnings

The Company's earnings were $8.3 million for the quarter ended June 30, 2016 compared to a loss of $293.1 million for the quarter ended June 30, 2015. The increase in earnings of $301.4 million is primarily a result of a lower loss in the Exploration and Production segment, as well as higher earnings in the Gathering segment and All Other category. Lower earnings in the Pipeline and Storage segment, Utility segment, Energy Marketing segment and Corporate category partially offset these increases.

The Company recorded a loss of $328.5 million for the nine months ended June 30, 2016 compared to a loss of $191.7 million for the nine months ended June 30, 2015. The increase in loss is primarily the result of a loss recognized in the Exploration and Production segment. In addition, the Pipeline and Storage segment, Gathering segment, Utility segment and Energy Marketing segment experienced a decline in earnings. Higher earnings in the Corporate and All Other categories partially offset these declines.

The Company's earnings for the quarter and nine months ended June 30, 2016 include non-cash impairment charges of $82.7 million ($47.9 million after-tax) and $915.6 million ($531.0 million after-tax), respectively, recorded during the quarter and nine months ended June 30, 2016 for the Exploration and Production segment's oil and gas producing properties, as discussed above. The Company's earnings for the quarter and nine months ended June 30, 2015 included 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. Additional discussion of earnings in each of the business segments can be found in the business segment information that follows. Note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted.

Earnings (Loss) by Segment

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Exploration and Production	$(19,165)	$(323,113)	$303,948	$(469,586)	$(349,955)	$(119,631)
Pipeline and Storage	17,323	17,714	(391)	59,794	61,868	(2,074)
Gathering	9,473	6,226	3,247	21,962	24,254	(2,292)
Utility	2,179	5,727	(3,548)	52,745	66,558	(13,813)
Energy Marketing	(590)	1,533	(2,123)	4,117	7,732	(3,615)
Total Reportable Segments	9,220	(291,913)	301,133	(330,968)	(189,543)	(141,425)
All Other	430	(28)	458	595	66	529
Corporate	(1,364)	(1,193)	(171)	1,863	(2,247)	4,110
Total Consolidated	$8,286	$(293,134)	$301,420	$(328,510)	$(191,724)	$(136,786)

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended June 30,		Nine Months Ended June 30,	
(Thousands)	2016	2015	2016	2015

			Increase (Decrease)			Increase (Decrease)
Gas (after Hedging)	$113,125	$105,108	$ 8,017	$323,655	$361,273	$ (37,618)
Oil (after Hedging)	42,797	52,887	(10,090)	125,831	161,804	(35,973)
Gas Processing Plant	576	621	(45)	1,849	2,394	(545)
Other	337	788	(451)	1,248	4,119	(2,871)
	$156,835	$159,404	$ (2,569)	$452,583	$529,590	$ (77,007)

30

Table of Contents

Production Volumes

	Three Months Ended June 30, 2016	2015	Increase (Decrease)	Nine Months Ended June 30, 2016	2015	Increase (Decrease)
Gas Production (MMcf)						
Appalachia	38,846	30,830	8,016	105,747	104,221	1,526
West Coast	763	807	(44)	2,310	2,375	(65)
Total Production	39,609	31,637	7,972	108,057	106,596	1,461
Oil Production (Mbbl)						
Appalachia	6	7	(1)	16	22	(6)
West Coast	722	752	(30)	2,183	2,234	(51)
Total Production	728	759	(31)	2,199	2,256	(57)

Average Prices

	Three Months Ended June 30, 2016	2015	Increase (Decrease)	Nine Months Ended June 30, 2016	2015	Increase (Decrease)
Average Gas Price/Mcf						
Appalachia	$1.73	$2.11	$ (0.38)	$1.84	$2.56	$ (0.72)
West Coast	$2.84	$3.52	$ (0.68)	$3.13	$4.30	$ (1.17)
Weighted Average	$1.75	$2.15	$ (0.40)	$1.87	$2.60	$ (0.73)
Weighted Average After Hedging	$2.86	$3.32	$ (0.46)	$3.00	$3.39	$ (0.39)
Average Oil Price/Bbl						
Appalachia	$58.28	$56.54	$ 1.74	$44.05	$62.29	$ (18.24)
West Coast	$38.89	$52.07	$ (13.18)	$34.02	$54.48	$ (20.46)
Weighted Average	$39.04	$52.12	$ (13.08)	$34.10	$54.56	$ (20.46)
Weighted Average After Hedging	$58.79	$69.65	$ (10.86)	$57.22	$71.72	$ (14.50)

2016 Compared with 2015

Operating revenues for the Exploration and Production segment decreased $2.6 million for the quarter ended June 30, 2016 as compared with the quarter ended June 30, 2015. Oil production revenue after hedging decreased $10.1 million due to a $10.86 per Bbl decrease in the weighted average price of oil after hedging coupled with a decrease in crude oil production. Largely offsetting this decrease, gas production revenue after hedging increased $8.0 million primarily due to the impact of increased gas production, partially offset by a $0.46 per Mcf decrease in the weighted average price of gas after hedging.

Operating revenues for the Exploration and Production segment decreased $77.0 million for the nine months ended June 30, 2016 as compared with the nine months ended June 30, 2015. Gas production revenue after hedging decreased $37.6 million primarily due to a $0.39 per Mcf decrease in the weighted average price of gas after hedging partially offset by an increase in gas production. Oil production revenue after hedging decreased $36.0 million due to a $14.50 per Bbl decrease in the weighted average price of oil after hedging coupled with a decrease in crude oil production. In addition, other revenue decreased $2.9 million primarily due to mark-to-market adjustments related to hedging ineffectiveness that occurred during the nine months ended June 30, 2015 that did not recur during the nine months ended June 30, 2016.

The Exploration and Production segment's loss for the quarter ended June 30, 2016 was $19.2 million compared with a loss of $323.1 million for the quarter ended June 30, 2015. The reduction in loss is attributed to lower impairment charges ($291.9

Table of Contents

million), as discussed above, higher natural gas production ($17.2 million), lower depletion expense ($16.1 million), lower other taxes ($1.5 million) and lower operating expenses ($2.6 million), largely due to lower personnel costs. The decrease in depletion expense is primarily due to the impact of impairment charges recognized in fiscal 2015 and fiscal 2016. The decrease in other taxes was largely due to IOG being billed for its share of previously incurred impact fees in accordance with the joint development agreement executed in December 2015, coupled with a decrease in Pennsylvania franchise taxes and a decrease in Kern and Ventura County taxes (due to a decrease in crude oil prices). These were partially offset by lower crude oil prices after hedging ($5.1 million), lower natural gas prices after hedging ($12.0 million), lower crude oil production ($1.4 million), lower interest income ($0.4 million), higher interest expense ($1.7 million), higher income tax expense ($2.9 million) and the impact of joint development agreement professional fees ($1.8 million). The joint development agreement professional fees incurred were related to professional services associated with the extension of the Marcellus Shale drilling joint development agreement with IOG in June 2016. The increase in interest expense was largely due to the Exploration and Production segment's share of the Company's $450 million long-term debt issuance in June 2015. The increase in income tax expense was primarily due to higher state taxes partially offset by a favorable tax settlement.

The Exploration and Production segment's loss for the nine months ended June 30, 2016 was $469.6 million compared with a loss of $350.0 million for the nine months ended June 30, 2015. The increased loss can be attributed to higher impairment charges ($121.7 million), as discussed above, the impact of joint development agreement professional fees ($4.6 million), lower crude oil prices after hedging ($20.7 million), lower natural gas prices after hedging ($27.7 million), lower crude oil production ($2.7 million), the impact of mark-to-market adjustments ($1.8 million), lower interest income ($0.7 million), higher interest expense ($6.1 million) and higher income tax expense ($2.8 million). The joint development agreement professional fees incurred were related to professional services associated with the Marcellus Shale drilling joint development agreement with IOG that was executed in December 2015 and extended in June 2016. The increase in interest expense was largely due to the Exploration and Production segment's share of the Company's $450 million long-term debt issuance in June 2015. The increase in income tax expense was primarily due to higher state taxes partially offset by a favorable tax settlement. These were partially offset by the impact of lower depletion expense ($52.6 million), higher natural gas production ($3.2 million), lower production costs ($7.9 million), lower other taxes ($3.3 million) and lower operating expenses ($2.4 million), largely due to lower personnel costs. The decrease in depletion expense is primarily due to the impact of impairment charges recognized in fiscal 2015 and fiscal 2016. The decrease in production costs is largely due to a decrease in well repair costs and a decrease in steam fuel costs associated with crude oil production in the West Coast region (due to lower fuel prices) coupled with a decrease in seasonal road maintenance (due to a milder winter) and decreases in various costs associated with a reduction in production (e.g. salt water disposal costs, equipment rental costs and compressor costs) in the Appalachian region. The decrease in other taxes was largely due to the decrease in impact fees and the decrease in Kern and Ventura County taxes, as discussed above.

Pipeline and Storage

Pipeline and Storage Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Firm Transportation	$56,734	$50,553	$ 6,181	$173,139	$163,770	$ 9,369
Interruptible Transportation	1,034	656	378	3,056	2,187	869
	57,768	51,209	6,559	176,195	165,957	10,238
Firm Storage Service	17,423	17,514	(91)	52,802	53,153	(351)
Interruptible Storage Service	22	—	22	92	3	89

Other	580	122	458	1,810	1,749	61
	$75,793	$68,845	$ 6,948	$230,899	$220,862	$ 10,037

32

Table of Contents

Pipeline and Storage Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Firm Transportation	173,379	155,819	17,560	558,160	572,453	(14,293)
Interruptible Transportation	6,354	3,105	3,249	18,469	8,833	9,636
	179,733	158,924	20,809	576,629	581,286	(4,657)

2016 Compared with 2015

Operating revenues for the Pipeline and Storage segment increased $6.9 million for the quarter ended June 30, 2016 as compared with the quarter ended June 30, 2015. The increase was primarily due to an increase in transportation revenues of $6.6 million. The increase in transportation revenues was largely due to demand charges for transportation service from Supply Corporation’s Westside Expansion and Modernization Project, Supply Corporation's Northern Access 2015 project, which were both fully placed in service during the first quarter of fiscal 2016, and Empire's Tuscarora Lateral Project, which was placed in service in November 2015. The increase in transportation revenues was partially offset by a decrease in Empire and Supply Corporation's short-term seasonal contracts. Operating revenues were also impacted by a 2% reduction in Supply Corporation's rates associated with the rate case settlement, which became effective November 1, 2015.

Operating revenues for the Pipeline and Storage segment increased $10.0 million for the nine months ended June 30, 2016 as compared with the nine months ended June 30, 2015. The increase was primarily due to an increase in transportation revenues of $10.2 million. The increase in transportation revenues was largely due to demand charges for transportation service from Supply Corporation’s Westside Expansion and Modernization Project, Supply Corporation's Northern Access 2015 project, which were both fully placed in service during the first quarter of fiscal 2016, and Empire's Tuscarora Lateral Project, which was placed in service in November 2015. The increase in transportation revenues was partially offset by a decrease in short-term contracts for both Empire and Supply Corporation. Operating revenues were also impacted by a 2% reduction in Supply Corporation's rates associated with the rate case settlement, which became effective November 1, 2015.

Transportation volume for the quarter ended June 30, 2016 increased by 20.8 Bcf from the prior year’s quarter. For the nine months ended June 30, 2016, transportation volume decreased by 4.7 Bcf from the prior year's nine-month period. The increase in transportation volume for the quarter primarily reflects the impact of the above mentioned expansion projects being placed in service. The decrease in transportation volume for the nine-month period primarily reflects warmer weather. Volume fluctuations, other than those caused by the addition or deletion of contracts, 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, 2016 were $17.3 million, a decrease of $0.4 million when compared with earnings of $17.7 million for the quarter ended June 30, 2015. The decrease in earnings is primarily due to higher operating expenses ($1.5 million), an increase in depreciation expense ($0.9 million), higher interest expense ($1.3 million), a decrease in the allowance for funds used during construction (equity component) of $0.6 million and higher income taxes ($0.7 million). The increase in operating expenses primarily reflects higher other post-retirement benefit costs, higher pension costs and higher compressor station expenses. The increase in depreciation expense was attributable to projects that were placed in service within the last year. The increase in interest expense was largely due to Supply Corporation's share of the Company's $450 million long-term debt issuance in June 2015. The decrease in allowance used for construction was mainly due to the above mentioned expansion projects being placed in service in the first quarter of 2016. The increase in income taxes was a result of Empire's provision-to-return adjustments combined with higher state taxes. The factors contributing to the earnings decrease were partially offset by the positive earnings impact of higher transportation revenues ($4.3 million), as discussed above.

The Pipeline and Storage segment’s earnings for the nine months ended June 30, 2016 were $59.8 million, a decrease of $2.1 million when compared with earnings of $61.9 million for the nine months ended June 30, 2015. The decrease in earnings is primarily due to higher operating expenses ($2.2 million), an increase in depreciation expense ($2.4 million), an increase in property taxes ($0.6 million), higher interest expense ($3.3 million) and higher income taxes ($0.3 million). The increase in operating expenses primarily reflects higher pension and other post-retirement benefit costs, higher pipeline integrity program expenses and higher compressor station expenses, offset slightly by lower personnel costs. The increase in depreciation expense was attributable to projects that were placed in service within the last year. The increase in property taxes was attributable to various expansion projects constructed over the last few years. The increase in interest expense was largely due to Supply Corporation's share of the Company's $450 million long-term debt issuance in June 2015. The increase in income taxes was a

Table of Contents

result of Empire's provision-to-return adjustments combined with higher state taxes. The factors contributing to the earnings decrease were partially offset by the positive earnings impact of higher transportation revenues ($6.7 million), as discussed above, combined with an increase in the equity component of the allowance for funds used during construction ($0.5 million). The increase in the equity component of the allowance for funds used during construction is attributable to higher Construction Work in Progress balances related to this segment's ongoing expansion projects.

Gathering

Gathering Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Gathering	$25,417	$16,748	$ 8,669	$65,601	$58,541	$ 7,060
Processing and Other Revenues	65	126	(61)	303	361	(58)
	$25,482	$16,874	$ 8,608	$65,904	$58,902	$ 7,002

Gathering Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Gathered Volume - (MMcf)	46,360	30,648	15,712	119,355	106,695	12,660

2016 Compared with 2015

Operating revenues for the Gathering segment increased $8.6 million for the quarter ended June 30, 2016 as compared with the quarter ended June 30, 2015. This increase was due to an increase in gathering revenues driven by a 15.7 Bcf increase in gathered volume. The overall increase in gathered volume was largely due to a 15.0 Bcf increase in gathered volume on Midstream Corporation’s Clermont Gathering System (Clermont), largely attributable to increased usage of the Clermont Gathering System due to the connection of additional wells to the gathering system as a result of the completion of the Northern Access 2015 project in November and December 2015. In addition, there was an increase in gathered volume on Midstream Corporation’s Covington Gathering System (Covington) of 1.2 Bcf due to previous shut-in wells (due to pricing curtailments) being brought back on line. These increases in gathered volume were partially offset by minor decreases including a 0.4 Bcf decrease in gathered volume on Midstream Corporation's Trout Run Gathering System (Trout Run). This decrease in gathered volume is primarily attributable to a decrease in Seneca's Marcellus Shale production in Lycoming County, Pennsylvania, which was partially offset by the impact of previously shut-in wells being brought back on line as pricing-related curtailments were lifted.

Operating revenues for the Gathering segment increased $7.0 million for the nine months ended June 30, 2016 as compared with the nine months ended June 30, 2015. This increase was due to an increase in gathering revenues driven by a 12.7 Bcf increase in gathered volume. The overall increase in gathered volume was largely due to a 33.9 Bcf increase in gathered volume on the Clermont Gathering System due to the connection of additional wells to the gathering system as a result of the completion of the Northern Access 2015 project in November and December 2015. These increases in gathered volume were partially offset by a 18.2 Bcf decrease in gathered volume on Trout Run and a 3.0 Bcf decrease in gathered volume on Covington. Most of these decreases in gathered volume are attributable to a decrease in Seneca's Marcellus Shale production primarily due to pricing-related curtailments largely experienced during the first two quarters of fiscal 2016.

The Gathering segment's earnings for the quarter ended June 30, 2016 were $9.5 million, an increase of $3.3 million when compared with earnings of $6.2 million for the quarter ended June 30, 2015. The increase in earnings is mainly due to the earnings impact of higher gathering revenues ($5.6 million), as discussed above, and the benefit of lower income taxes ($0.3 million). The decrease in income taxes was largely due to the impact of the provision-to-return adjustments net of an increase in state income taxes. These increases are partially offset by higher interest expense ($1.3 million), higher depreciation expense ($0.9 million) and higher operating expenses ($0.5 million). The increase in interest expense is largely due to the Gathering segment's share of the Company's $450 million long-term debt issuance in June 2015 coupled with a decrease in capitalized interest,

Table of Contents

which was due to various Clermont projects being placed in service. The completion of these projects increased the plant balances subject to depreciation and led to an increase in maintenance expense.

The Gathering segment’s earnings for the nine months ended June 30, 2016 were $22.0 million, a decrease of $2.3 million when compared with earnings of $24.3 million for the nine months ended June 30, 2015. The decrease in earnings is mainly due to higher interest expense ($4.3 million), higher depreciation expense ($2.2 million) and higher operating expenses ($1.1 million). The increase in interest expense is largely due to the Gathering segment's share of the Company's $450 million long-term debt issuance in June 2015 coupled with a decrease in capitalized interest, which was due to various Clermont projects being placed in service. A large increase in plant balances (largely due to various Clermont projects being placed in service), partially offset by the non-recurrence of long-lived asset impairment charges recorded in March 2015 related to the gathering facilities at Midstream Corporation's Tionesta Gathering System, led to an overall increase in depreciation expense. The increase in operating expenses was largely due to the significant growth of Clermont and its impact on maintenance expense. These decreases are partially offset by the earnings impact of higher gathering revenue ($4.6 million), as discussed above, and the impact of lower income tax ($0.7 million)due to the provision-to-return adjustments discussed above.

Utility

Utility Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Retail Sales Revenues:						
Residential	$72,018	$74,872	$ (2,854)	$315,927	$436,006	$(120,079)
Commercial	8,400	8,644	(244)	39,866	56,707	(16,841)
Industrial	185	337	(152)	1,604	2,388	(784)
	80,603	83,853	(3,250)	357,397	495,101	(137,704)
Transportation	25,740	26,543	(803)	106,751	122,653	(15,902)
Off-System Sales	—	—	—	1,877	11,773	(9,896)
Other	1,954	2,220	(266)	7,886	14,192	(6,306)
	$108,297	$112,616	$ (4,319)	$473,911	$643,719	$(169,808)

Utility Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Retail Sales:						
Residential	9,196	8,287	909	46,814	56,315	(9,501)
Commercial	1,251	1,142	109	6,765	8,239	(1,474)
Industrial	401	34	367	635	316	319
	10,848	9,463	1,385	54,214	64,870	(10,656)
Transportation	13,864	13,993	(129)	58,778	68,509	(9,731)
Off-System Sales	—	—	—	1,243	3,787	(2,544)
	24,712	23,456	1,256	114,235	137,166	(22,931)

35

Degree Days

Three Months Ended June 30,	Normal	2016	2015	Percent Colder (Warmer) Than Normal[1]	Prior Year[1]
Buffalo	912	927	778	1.6 %	19.2 %
Erie	871	936	729	7.5 %	28.4 %
Nine Months Ended June 30,					
Buffalo	6,491	5,567	6,898	(14.2)%	(19.3)%
Erie	6,057	5,159	6,535	(14.8)%	(21.1)%

(1) Percents compare actual 2016 degree days to normal degree days and actual 2016 degree days to actual 2015 degree days.

2016 Compared with 2015

Operating revenues for the Utility segment decreased \$4.3 million for the quarter ended June 30, 2016 as compared with the quarter ended June 30, 2015. This decrease largely resulted from a \$3.3 million decrease in retail gas sales revenues and a \$0.8 million decrease in transportation revenues. The decrease in retail gas sales revenue was largely a result of a decrease in the cost of gas sold (per Mcf). The decrease in transportation revenues and volumes was marginal.

Operating revenues for the Utility segment decreased \$169.8 million for the nine months ended June 30, 2016 as compared with the nine months ended June 30, 2015. This decrease largely resulted from a \$137.7 million decrease in retail gas sales revenues. In addition, there was a \$9.9 million decrease in off-system sales, a \$15.9 million decrease in transportation revenues, and a \$6.3 million decrease in other revenues. The decrease in retail gas sales revenue was largely a result of a decrease in the cost of gas sold (per Mcf) coupled with lower volumes due to warmer weather. The \$15.9 million decrease in transportation revenues was primarily due to a 9.7 Bcf decrease in transportation throughput due to warmer weather experienced during the fiscal 2016 winter relative to the fiscal 2015 winter. The decrease in off-system sales was due to market conditions that have continued to reduce the price at which off-system gas could be sold as well as the opportunity for such sales. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal. The decrease in other revenues was largely due to the non-recurrence of a regulatory adjustment recorded during fiscal 2015 to recognize an under collection of a New York State regulatory assessment from customers.

The Utility segment's earnings for the quarter ended June 30, 2016 were \$2.2 million, a decrease of \$3.5 million when compared with earnings of \$5.7 million for the quarter ended June 30, 2015. The decrease in earnings was largely attributable to the earnings impact of higher operating expenses of \$1.7 million (largely personnel costs). Earnings were further reduced by an increase in depreciation expense of \$0.5 million (largely due to higher plant balances) and lower margins of \$1.0 million.

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, 2016, the WNC increased earnings by approximately \$0.1 million as the weather was warmer than normal on a billed basis (as opposed to on a calendar basis) for April and May. For the quarter ended June 30, 2015, the WNC increased earnings by approximately $0.1 million, as the weather was warmer than normal.

The Utility segment's earnings for the nine months ended June 30, 2016 were $52.7 million, a decrease of $13.9 million when compared with earnings of $66.6 million for the nine months ended June 30, 2015. The decrease in earnings was largely attributable to the impact of warmer weather in fiscal 2016 compared to fiscal 2015 ($12.9 million) and $3.1 million of regulatory adjustments (discussed above). Earnings were further reduced by an increase in depreciation expense of $1.0 million (largely due to higher plant balances). The negative earnings impact associated with these factors was partially offset by the positive earnings impact associated with a decrease in operating expenses of $1.9 million (primarily due to a reduction in personnel costs), and lower income tax expense of $1.8 million (largely due to lower state income taxes).

For the nine months ended June 30, 2016, the WNC increased earnings by approximately $4.4 million, as the weather was warmer than normal. For the nine months ended June 30, 2015, the WNC reduced earnings by approximately $2.5 million, as the weather was colder than normal.

Table of Contents

Energy Marketing

Energy Marketing Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Natural Gas (after Hedging)	$17,635	$22,799	$ (5,164)	$78,574	$143,495	$ (64,921)
Other	4	—	4	108	54	54
	$17,639	$22,799	$ (5,160)	$78,682	$143,549	$ (64,867)

Energy Marketing Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Natural Gas – (MMcf)	8,537	8,289	248	33,800	40,215	(6,415)

2016 Compared with 2015

Operating revenues for the Energy Marketing segment decreased $5.2 million for the quarter ended June 30, 2016 as compared with the quarter ended June 30, 2015. Operating revenues for the Energy Marketing segment decreased $64.9 million for the nine months ended June 30, 2016 as compared with the nine months ended June 30, 2015. 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. For the nine months ended June 30, 2016, a decrease in volume sold to retail customers as a result of warmer weather also contributed to the decline in operating revenues.

The Energy Marketing segment recorded a loss for the quarter ended June 30, 2016 of $0.6 million, a decrease of $2.1 million when compared with earnings of $1.5 million for the quarter ended June 30, 2015. The decrease is primarily due to lower margin of $2.2 million. Margin was negatively impacted by changes in natural gas prices at local purchase points relative to NYMEX-based customer sales contracts.

The Energy Marketing segment’s earnings for the nine months ended June 30, 2016 were $4.1 million, a decrease of $3.6 million when compared with earnings of $7.7 million for the nine months ended June 30, 2015. This decrease in earnings was largely attributable to lower margin of $3.8 million. The decrease in margin largely reflects the margin impact associated with the decrease in volume sold to retail customers as a result of warmer weather during the nine months ended June 30, 2016 compared to the nine months ended June 30, 2015. Margin was also negatively impacted by changes in natural gas prices at local purchase points relative to NYMEX-based customer sales contracts. This decrease was partially offset by an increase to margin due to an increase in the benefit the Energy Marketing segment realized from its contracts for storage capacity.

Corporate and All Other

2016 Compared with 2015

Corporate and All Other operations recorded a loss of $0.9 million for the quarter ended June 30, 2016 compared to a loss of $1.2 million for the quarter ended June 30, 2015. For the nine months ended June 30, 2016, Corporate and All Other operations recorded earnings of $2.5 million compared to a loss of $2.2 million recorded for the nine months ended June 30, 2015. The earnings increase for the quarter can be attributed to lower operating expenses of $0.4 million (primarily due to lower personnel costs) and higher margins of $0.6 million (from the sale of standing timber and stumpage tracts by Seneca's land and timber division), partially offset by higher income tax expense of $0.9 million. The earnings increase for the nine-month period ending June 30, 2016 can be attributed to lower income tax expense of $1.2 million and a death benefit gain on life insurance of $1.6 million that was recognized during the nine months ended June 30, 2016. In addition, lower operating expenses of $1.2 million (primarily due to a decrease in personnel costs) and higher margins of $0.6 million (from the sale of standing timber and stumpage tracts by Seneca's land and timber division) further increased earnings during the nine months ended June 30, 2016.

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

Interest on long-term debt increased $6.7 million for the quarter ended June 30, 2016 as compared with the quarter ended June 30, 2015. For the nine months ended June 30, 2016, interest on long-term debt increased $21.4 million as compared with the nine months ended June 30, 2015. This increase is primarily due to additional long-term debt that was issued in fiscal 2015. The Company issued $450 million of 5.20% notes in June 2015. Additionally, capitalized interest (mostly in Midstream Corporation) decreased (as a result of various projects being placed into service), which increased interest expense for the quarter and nine months ended June 30, 2016 as compared to the quarter and nine months ended June 30, 2015.

CAPITAL RESOURCES AND LIQUIDITY

The Company's primary sources of cash during the nine-month period ended June 30, 2016 consisted of cash provided by operating activities and proceeds from Seneca's joint development agreement with IOG. Proceeds from IOG are reflected as net proceeds from the sale of oil and gas producing properties on the Statement of Cash Flows. The Company's primary source 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. These sources of cash were supplemented by net proceeds from the issuance of common stock for both the nine months ended June 30, 2016 and June 30, 2015, 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 $460.0 million for the nine months ended June 30, 2016, a decrease of $252.6 million compared with $712.6 million provided by operating activities for the nine months ended June 30, 2015. The decrease in cash provided by operating activities reflects lower cash provided by operating activities in the Exploration and Production segment and the Utility 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 and curtailed production. The decrease in the Utility segment is primarily due to the timing of gas cost recovery.

Table of Contents

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets totaled $407.2 million during the nine months ended June 30, 2016 and $704.9 million during the nine months ended June 30, 2015. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Nine Months Ended June 30, (Millions)	2016		2015		Increase(Decrease)
Exploration and Production:					
Capital Expenditures	$214.9	(1)	$437.4	(2)	$ (222.5)
Pipeline and Storage:					
Capital Expenditures	76.0	(1)	114.7	(2)	(38.7)
Gathering:					
Capital Expenditures	43.7	(1)	87.2	(2)	(43.5)
Utility:					
Capital Expenditures	72.3	(1)	65.3	(2)	7.0
All Other:					
Capital Expenditures	0.3	(1)	0.3	(2)	—
	$407.2		$704.9		$ (297.7)

(1) At June 30, 2016, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $26.7 million, $7.6 million, $2.8 million and $7.3 million, respectively, of non-cash capital expenditures. At September 30, 2015, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $46.2 million, $33.9 million, $22.4 million and $16.5 million, respectively, of non-cash capital expenditures. The capital expenditures for the Exploration and Production segment do not include any proceeds received from the sale of oil and gas assets.

(2) At June 30, 2015, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $64.3 million, $28.0 million, $21.4 million and $8.9 million, respectively, of non-cash 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 non-cash capital expenditures.

Exploration and Production

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2016 were primarily well drilling and completion expenditures and included approximately $184.9 million for the Appalachian region (including $172.9 million in the Marcellus Shale area) and $30.0 million for the West Coast region. These amounts included approximately $85.4 million spent to develop proved undeveloped reserves.

On December 1, 2015, Seneca and IOG - CRV Marcellus, LLC (IOG), an affiliate of IOG Capital, LP, and funds managed by affiliates of Fortress Investment Group, LLC, executed a joint development agreement that allows IOG to participate in the development of certain oil and gas interests owned by Seneca in Elk, McKean and Cameron Counties, Pennsylvania. On June 13, 2016, Seneca and IOG executed an extension of the joint development agreement. Under the terms of the extended agreement, Seneca and IOG will jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. The extended joint development agreement gives IOG the option to participate in a 7-well Marcellus pad that is expected to be completed before December 31, 2017, which, if exercised, would increase the maximum number of joint development wells to 82. Under the original joint development agreement, IOG had committed to develop 42 Marcellus wells. As of June 30, 2016, Seneca had received $115.2 million of cash and had recorded a $22.1 million receivable in recognition of IOG funding that is due to Seneca for costs previously incurred to develop a portion of the first 75 joint development wells. The cash proceeds and receivable were recorded by Seneca as a $137.3 million reduction of property, plant and equipment. For further discussion of the extended joint development agreement, refer to Item 1 at Note 1 - Summary of Significant Accounting Policies under the heading “Property, Plant and Equipment.”

On June 30, 2016, Seneca sold the majority of its Upper Devonian wells in Pennsylvania. While the proceeds from the sale were not significant, it did result in a $58.4 million reduction of its Asset Retirement Obligation at June 30, 2016.

Table of Contents

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.

Pipeline and Storage

The Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2016 were mainly for expenditures related to Empire and Supply Corporation's Northern Access 2016 Project ($22.4 million), Supply Corporation's Northern Access 2015 Project ($12.9 million), Supply Corporation's Westside Expansion and Modernization Project ($7.0 million), Empire and Supply Corporation's Tuscarora Lateral Project ($5.9 million) and Supply Corporation's Line D Expansion Project ($5.4 million). In addition, the Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2016 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, 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) and also included additions, improvements, and replacements to this segment’s transmission and gas storage systems.

In light of the continuing 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, 2016, the total amount reserved for the Pipeline and Storage segment’s preliminary survey and investigation costs was $8.0 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 on-system markets, and 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.

The Westside Expansion and Modernization Project, which further increases Supply Corporation's capacity to move gas north and south on its Line N system to Texas Eastern Transmission, LP (“TETCO”) at Holbrook and Tennessee Gas Pipeline ("TGP") at Mercer, was fully placed in service during the first quarter of fiscal 2016. The cost estimate for this project is $82.3 million, of which $43.3 million is related to expansion and the remainder is for replacement. As of June 30, 2016, approximately $74.9 million has been spent on the Westside Expansion and Modernization Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2016.

Supply Corporation and TGP jointly developed the Northern Access 2015 project that combines 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. Northern Access 2015 was fully placed in service during the first quarter of fiscal 2016. The cost estimate for the Northern Access 2015 project is $67.1 million. As of June 30, 2016, approximately $64.4 million has been spent on the Northern Access 2015 project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2016.

Supply Corporation and Empire have been working with Seneca to develop a project which would move significant prospective Marcellus production from Seneca's Western Development Area at Clermont to an Empire interconnection with TransCanada Pipeline at Chippawa ("Northern Access 2016") and an interconnection with TGP's 200 Line in East Aurora, New York. Similar to the goal of the Northern Access 2015 project, the separate and distinct Northern Access 2016 project would provide an outlet to Dawn-indexed markets in Canada and to the TGP line serving the U.S. Northeast. The Northern Access 2016 project involves the construction of approximately 99 miles of largely 24" pipeline and approximately 27,500 horsepower of compression on the two systems. The target in-service date for this project is November 1, 2017. The preliminary cost estimate for the Northern Access 2016 project is $455 million. Supply Corporation, Empire and Seneca 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 and amended that application on November 2, 2015. On July 27, 2016, the FERC issued the Environmental Assessment for the project, completing a significant milestone in the FERC review process. As of June 30, 2016, approximately $41.5 million has been spent on the Northern Access 2016 project, including $13.2 million that has been spent to study the project. The Company has determined it is highly probable that the project will be built. Accordingly, previous reserves have been reversed and this $13.2 million of project costs has been reestablished as a Deferred Charge on the Consolidated Balance Sheet. The remaining $28.3 million spent on the project has been capitalized as Construction Work in Progress.

On November 21, 2014, Supply Corporation concluded an Open Season for an expansion of its Line D pipeline (“Line D Expansion”) that is intended to allow growing on-system markets to avail themselves of economical gas supply on the TGP 300 line, at an existing interconnect at Lamont, Pennsylvania, and provide increased capacity into the Erie, Pennsylvania market area. Following negotiations with prospective shippers, Supply Corporation executed five precedent agreements for a total of 77,500 Dth per day for terms of ten years. The project involves construction of a new 4,152 horsepower Keelor Compressor Station and modifications to the Roystone and Bowen compressor stations at an estimated capital cost of approximately $27.9 million. The project will also provide system modernization benefits. Supply Corporation filed on December 22, 2015 for authorization to construct this project under its FERC blanket certificate and completed the FERC notice period on February 26, 2016. Based on the anticipated timing of the PaDEP Air Permit, the target in-service date is April 1, 2017. As of June 30, 2016, approximately $5.4 million has been capitalized as Construction Work in Progress for the Line D Expansion project.

Empire and Supply Corporation's Tuscarora Lateral Project, which allows Empire to provide firm no-notice storage and transportation services to new and existing shippers on its system, was placed in service in November 2015. The cost estimate for the Tuscarora Lateral Project is $64.8 million. As of June 30, 2016, approximately $61.4 million has been spent on the Tuscarora Lateral Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2016.

Empire is developing an expansion of its system, and concluded an Open Season on November 18, 2015, that would allow for the transportation of approximately 300,000 Dth per day of additional Marcellus supplies from Millennium Pipeline at Corning, from Supply Corporation at Tuscarora, or from new interconnections in Tioga County, Pennsylvania, to the TransCanada Pipeline and the TGP 200 Line (“Empire North Project”), and is negotiating precedent agreements with prospective shippers for that capacity. The preliminary cost estimate for the Empire North Project is approximately $185 million dependent on final receipt and delivery point selections. As of June 30, 2016, approximately $0.3 million has been spent to study this project, all of which has been included in preliminary survey and investigation charges and has been fully reserved for at June 30, 2016.

Gathering

The majority of the Gathering segment capital expenditures for the nine months ended June 30, 2016 and June 30, 2015 were for the construction of Midstream Corporation’s Clermont Gathering System, as discussed below.

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 total cost estimate for the continued buildout will be dependent on the nature and timing of the shippers', including Seneca's, long-term plans. As of June 30, 2016, approximately $254.3 million has been spent on the Clermont Gathering System, including approximately $37.8 million spent during the nine months ended June 30, 2016, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2016.

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 42 miles of backbone and in-field gathering pipelines and two compressor stations. As of June 30, 2016, the Company has spent approximately $166.7 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, 2016.

Utility

The majority of the Utility segment capital expenditures for the nine months ended June 30, 2016 and June 30, 2015 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, 2016 and June 30, 2015 also include $14.0 million and $12.9 million, respectively, related to the replacement of the Utility segment's customer information system, which was placed in service in May 2016.

Table of Contents

Project Funding

The Company has been financing the Pipeline and Storage segment and Gathering segment projects mentioned above, as well as the Exploration and Production segment capital expenditures, with cash from operations and both short and long-term borrowings. Going forward, while the Company expects to use cash on hand and cash from operations as the first means of financing these projects, the Company may issue short-term debt as necessary during the remainder of fiscal 2016 and much of fiscal 2017 to help meet its capital expenditure 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. As disclosed above, the Company expects to be precluded from issuing new long-term debt until the second half of fiscal 2017 as a means of financing projects. Given the current commodity price environment, the Company expects to record an additional significant ceiling test impairment during the quarter ended September 30, 2016.

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

The Company had no consolidated short-term debt outstanding at June 30, 2016 and September 30, 2015. The maximum amount of short-term debt outstanding during the nine months ended June 30, 2016 was $62.4 million. While the Company did not have any outstanding commercial paper and short-term notes payable to banks at June 30, 2016, 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.

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. On September 30, 2015, the Company entered into a Second Amended and Restated Credit Agreement (Credit Agreement) with a syndicate of the same 14 banks. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through December 5, 2019, plus a $500.0 million 364-day unsecured committed revolving credit facility through September 29, 2016. 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. The commercial paper program is backed by the Credit Agreement, which provides that the Company's debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through December 5, 2019. At June 30, 2016, the Company’s debt to capitalization ratio (as calculated under the facility) was .58. The constraints specified in the Credit Agreement would have permitted an additional $751.0 million 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.

A downgrade in the Company's credit ratings could increase borrowing costs, negatively impact the availability of capital from banks, commercial paper purchasers and other sources, and require the Company’s subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. If the Company is not able to maintain investment-grade credit ratings, it may not be able to access commercial paper markets. However, the Company expects that it could borrow under its credit facilities or rely upon other liquidity sources, including cash provided by operations.

The Credit Agreement 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 Credit Agreement. 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, 2016, the Company did not have any debt outstanding under the Credit Agreement.

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, 2016 and 2015 had a maturity date within the following twelve-month period.

The Company’s embedded cost of long-term debt was 5.53% at both June 30, 2016 and June 30, 2015.

Under the Company’s existing indenture covenants, at June 30, 2016, the Company expects to be precluded from issuing additional long-term unsecured indebtedness until the second half of fiscal 2017 as a result of impairments of its oil and gas properties recognized during the year ended September 30, 2015 and the nine months ended June 30, 2016, as discussed above. The 1974 indenture would not preclude the Company from issuing new indebtedness to replace maturing debt. If the Company experiences an additional impairment of its oil and gas properties in the fourth quarter of fiscal 2016, the Company, under its 1974 indenture, expects to continue to be precluded from issuing incremental long-term debt until the second half of fiscal 2017. 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 $98.6 million (or 4.7%) of the Company’s long-term debt (as of June 30, 2016) 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 $23.9 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, 2016, the Company contributed $4.0 million to its Retirement Plan and $2.3 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2016, the Company does not expect to make any additional contributions to the Retirement Plan. In the remainder of 2016, the Company expects to contribute $0.3 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 have been adopted or 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. While many of the final rules adopted by the CFTC and other regulators place specific conditions on the operations of swap dealers and major swap participants, 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. For example, the Dodd-Frank Act requires that certain swaps be cleared and traded on exchanges or swap execution facilities, with certain exceptions for swaps that end-users such as the Company use to hedge or mitigate commercial risk. While the Company expects to be excluded from these clearing and trading requirements for swaps used to hedge its commercial risks, there may be increased transaction costs or decreased liquidity with respect to entering into such uncleared and non-exchange traded swaps. Also, during the fourth calendar quarter of 2015, the bank regulators and the CFTC, respectively, adopted final margin rules that apply to swap dealers and major swap participants with respect to uncleared swaps. While these rules do not impose a requirement on swap dealers and major swap participants to collect margin for uncleared swaps from non-financial end users such as the Company, the obligations may increase the costs of uncleared swaps. For example, among other things, to fulfill obligations imposed on them under the rules, swap dealers may seek to negotiate collateral or other credit arrangements in their swap agreements with counterparties, which would increase the cost of transactions in uncleared swaps. In May 2016, the CFTC issued a supplemental proposal to its position limit rules that would impose speculative position limits on positions in 28 core physical commodity contracts as well as economically equivalent futures, options and swaps. While the Company does not intend to enter into positions on a speculative basis, such rules could nevertheless impact the ability of the Company to enter into certain derivative hedging transactions with respect to such commodities. 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.

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, 2016, 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's (assuming the derivative is in a gain position) or the Company’s (assuming the derivative is in a loss position) 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 2015 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 the Pennsylvania division does not have a rate case on file, see below for a description of the current 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

Table of Contents

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.

On April 28, 2016, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by approximately $41.7 million. Distribution Corporation explained in the filing that its request for rate relief was necessitated by a revenue requirement driven primarily by rate base growth, higher operating expense and higher depreciation expense that are not reflected in current rates, among other things. The rate filing includes a proposal for system infrastructure modernization that includes the acceleration of Distribution Corporation’s replacement of certain gas mains, which are of a type generically classified by the NYPSC as “leak prone pipe”. The NYPSC may accept, reject or modify the Company’s filing. In June of 2016, the administrative law judge assigned to the case adopted a schedule that requires Staff and intervenor testimony to be filed by August 26, 2016, and establishes the commencement of an evidentiary hearing on October 5, 2016. Assuming standard procedure, new rates, if accepted, would become effective on or about April 1, 2017. The outcome of the proceeding cannot be ascertained at this time.

In an unrelated action, on February 23, 2016, the NYPSC issued an Order Resetting Retail Energy Markets and Establishing Further Process, in which the NYPSC states it is taking action to address certain unfair business practices currently found in the energy services industry and to ensure residential and small non-residential commercial customers are receiving value from the retail energy markets (“Resetting Order”). A number of retail marketers (“Petitioners”) challenged the Resetting Order in New York State Supreme Court and obtained a temporary restraining order from the Court, staying enforcement of a number of provisions of the Resetting Order. On July 22, 2016, the Court issued a Decision and Order vacating those provisions of the Resetting Order on the grounds that the Petitioners were denied procedural due process and that the Resetting Order was, in part, arbitrary and irrational. The Court also affirmed the NYPSC's jurisdiction over retail marketers and found that the NYPSC has jurisdiction over rates charged by retail energy companies. The Court also remitted the matter back to the NYPSC for further proceedings. There is the possibility that either the Commission or the Petitioners may appeal the decision. Also related to the New York retail energy markets, on July 15, 2016, the NYPSC issued an Order Regarding the Provision of Service to Low-Income Customers by Energy Service Companies, in which the NYPSC generally instituted a moratorium on enrollments of low-income program participants with retail marketers and to the extent such customers are already enrolled with retail marketers, mandated a return, over a period of time, of such customers to the utility as bundled sales customers (“Moratorium Order”). Distribution Corporation and NFR are carefully monitoring industry impacts stemming from the Resetting Order, the related Court decision and the Moratorium Order, which may result in the migration of a significant number of residential and small non-residential customers back to Distribution Corporation as the provider of last resort.

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's current rate settlement requires a rate case filing no later than December 31, 2019 and prohibits any party from seeking to initiate a rate case proceeding before September 30, 2017.

By order dated January 21, 2016, the FERC began a NGA Section 5 rate review of Empire's rates. As required by that order, Empire filed a Cost and Revenue Study on April 5, 2016. On May 25, 2016, Empire reached a settlement in principle on this matter that would, among other things, reduce certain of Empire's maximum transportation rates over a 14-month period, which, based on current contracts, is estimated to reduce Empire's revenues on a yearly basis by between $3 million to $4 million. The settlement also reduces Empire's depreciation rate from 2.5% to 2%. In addition, the settlement provides an annual revenue sharing mechanism, pursuant to which non-expansion transportation revenues exceeding $73.5 million are shared on a tiered basis. Under the settlement, Empire will be required to make a general rate filing no later than July 1, 2021. On July 22, 2016, Empire filed the settlement at the FERC and is awaiting approval. The settlement is not expected to have a material impact on the Company's financial condition.

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. Recently, the EPA adopted final regulations that set methane and volatile organic compound emissions standards for new or modified oil and gas emissions sources. These new rules impose more stringent leak detection and repair requirements, and further address reporting and control of methane and volatile organic compound emissions. 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. With respect to its operations in California, 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 aims to reduce greenhouse gas emissions could also include carbon taxes, restrictive permitting, increased efficiency standards, and incentives or mandates to conserve energy or use renewable energy sources. Federal, state or local governments may, for example, provide tax advantages and other subsidies to support alternative energy sources, mandate the use of specific fuels or technologies, or promote research into new technologies to reduce the cost and increase the scalability of alternative energy sources. These climate change and greenhouse gas initiatives 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. They could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, impose additional monitoring and reporting requirements, and 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. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;
2. Changes in the price of natural gas or oil;

Table of Contents

3. 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;
4. 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;
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. 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;
7. 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;
8. 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;
9. Other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date;
10. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
11. Uncertainty of oil and gas reserve estimates;
12. Significant differences between the Company's projected and actual production levels for natural gas or oil;
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.

Table of Contents

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, 2016.

Changes in Internal Control Over Financial Reporting

In May 2016, Distribution Corporation implemented SAP Customer Relationship and Billing as its new customer information and billing system. This system change was a result of an evaluation of the capability of the legacy CIS (Customer Information System) used to support the evolving needs of the Utility segment and was not the result of any actual or perceived deficiency in the legacy system. This implementation resulted in certain changes to Distribution Corporation's processes and internal controls impacting financial reporting. While there are inherent risks involved with the implementation of any new system, management believes that it is adequately monitoring and managing the transition.

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended June 30, 2016 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 2015 Form 10-K, as amended by Item 1A of Part II of the Company's Form 10-Q for the quarter ended March 31, 2016, 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 2015 Form 10-K and March 31, 2016 Form 10-Q and should otherwise be read in conjunction with all of the risk factors disclosed in the 2015 Form 10-K.

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, the Company has been precluded since October 1, 2015 from issuing incremental long-term debt as a result of impairments (i.e., write-downs) of its oil and gas properties. Given the impairments recognized through June 30, 2016 and an expected impairment during the quarter ended September 30, 2016, the Company expects to be precluded from issuing incremental long-term debt until the second half of fiscal 2017, absent amendment or waiver by existing noteholders of a covenant in the 1974 indenture. 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, negatively impact the availability of capital from banks, commercial paper purchasers and other sources, and require the Company’s subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. If the Company is not able to maintain investment-grade credit ratings, it may not be able to access commercial paper markets.

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 a 12-month historical average price 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 fiscal year ended September 30, 2015, the Company recognized pre-tax impairment charges on its oil and natural gas properties of $1.1 billion. For the nine-months ended June 30, 2016, the Company recognized a pre-tax impairment charge on its oil and natural gas properties of $915.6 million. Given the potential for significant fluctuations in oil and natural gas prices, the Company expects to experience an additional ceiling test impairment in that quarter (the fourth quarter of fiscal 2016).

Environmental regulation significantly affects the Company’s business.

The Company’s business operations are subject to federal, state, and local laws and regulations relating to environmental protection. These laws and regulations concern the generation, storage, transportation, disposal, emission or discharge of pollutants, contaminants, hazardous substances and greenhouse gases into the environment, the reporting of such matters, and the general protection of public health, natural resources, wildlife and the environment. For example, currently applicable environmental laws and regulations restrict the types, quantities and concentrations of materials that can be released into the environment in connection with regulated activities, limit or prohibit activities in certain protected areas, and may require the Company to investigate and/or remediate contamination at certain current and former properties regardless of whether such contamination resulted from the Company’s actions or whether such actions were in compliance with applicable laws and regulations at the time they were taken. Moreover, spills or releases of regulated substances or the discovery of currently unknown contamination could expose the Company to material losses, expenditures and environmental, health and safety liabilities. Such liabilities could include penalties, sanctions or claims for damages to persons, property or natural resources brought on behalf of the government or private litigants that could cause the Company to incur substantial costs or uninsured losses.

In addition, the Company must obtain, maintain and comply with numerous permits, leases, approvals, consents and certificates from various governmental authorities before commencing regulated activities. In connection with such activities, the Company may need to make significant capital and operating expenditures to detect, repair and/or control air emissions, to control water discharges or to perform certain corrective actions to meet the conditions of the permits issued pursuant to applicable environmental laws and regulations. Any failure to comply with applicable environmental laws and regulations and the terms and conditions of its environmental permits and authorizations

could result in the assessment of significant administrative, civil and/or criminal penalties, the imposition of investigatory or remedial obligations and corrective actions, the revocation of required permits, or the issuance of injunctions limiting or prohibiting certain of the Company's operations.
Costs of compliance and liabilities could negatively affect the Company's results of operations, financial condition and cash flows. In addition, compliance with environmental laws and regulations could require unexpected capital expenditures at the Company's facilities, temporarily shut down the Company's facilities or delay or cause the cancellation of expansion projects or oil and natural gas drilling activities. Because the costs of complying with environmental regulations are significant, additional regulation could negatively affect the Company's business. Although the Company cannot predict the impact of the interpretation or enforcement of EPA standards or other federal, state and local laws or regulations, the Company's costs could increase if environmental laws and regulations change.

Table of Contents

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. Under the Federal Clean Air Act, the EPA requires that new stationary sources of significant greenhouse gas emissions or major modifications of existing facilities obtain permits covering such emissions. The EPA recently adopted final regulations that set methane emissions standards for new oil and natural gas emission sources. In addition, the EPA issued draft guidelines for voluntarily reducing emissions from existing equipment and processes in the oil and natural gas industry and is moving toward the regulation of emissions from existing sources as well. Further, 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. With respect to its operations in California, 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 aims to reduce greenhouse gas emissions could also include carbon taxes, restrictive permitting, increased efficiency standards, and incentives or mandates to conserve energy or use renewable energy sources. Federal, state or local governments may, for example, provide tax advantages and other subsidies to support alternative energy sources, mandate the use of specific fuels or technologies, or promote research into new technologies to reduce the cost and increase the scalability of alternative energy sources. These climate change and greenhouse gas initiatives 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. They could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, impose additional monitoring and reporting requirements, and reduce demand for oil and natural gas.

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

On April 1, 2016, the Company issued a total of 4,800 unregistered shares of Company common stock to eight non-employee directors of the Company then serving on the Board of Directors of the Company, 600 shares to each such director. On June 29, 2016, the Company issued 46 unregistered shares of Company common stock to Rebecca Ranich, 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, 2016. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under Share Repurchase Plans or Programs (b)
Apr. 1 - 30, 2016	595	$51.59	—	6,971,019
May 1 - 31, 2016	1,740	$54.83	—	6,971,019
June 1 - 30, 2016	10,155	$55.76	—	6,971,019
Total	12,490	$55.44	—	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, 2016, 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.

Table of Contents

Item 6. Exhibits

Exhibit Number	Description of Exhibit
•	Form of Indemnification Agreement between National Fuel Gas Company and Rebecca Ranich, Director (Exhibit 10.1, Form 8-K dated September 18, 2006).
10.1	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective June 9, 2016.
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Twelve Months Ended June 30, 2016 and the Fiscal Years Ended September 30, 2012 through 2015.
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, 2016 and 2015.
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, 2016 and 2015, (ii) the Consolidated Statements of Comprehensive Income for the three and nine months ended June 30, 2016 and 2015, (iii) the Consolidated Balance Sheets at June 30, 2016 and September 30, 2015, (iv) the Consolidated Statements of Cash Flows for the nine months ended June 30, 2016 and 2015 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.

Table of Contents

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 5, 2016